NISSEN 8/87

INTERMOUNTAIN GENERATING STATION

PERFORMANCE TEST REPORT

UNIT 1
VOLUME 1
TURBINE CYCLE

IPP

INTERMOUNTAIN POWER PROJECT

BLACK & VEATCH/engineers-architects

1987

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1.0 INTRODUCTION

This report describes efficiency testing of power plant equipment for Intermountain Power Project Unit 1. It covers performance results, sample calculations, and data related to the six test runs. The tests were conducted from June 22, 1986 through June 28, 1986. The unit was first synchronized in February 1986. The following groups of personnel assisted in and observed the tests.

Babcock & Wilcox
Black & Veatch
General Electric
Intermountain Power Project Startup
Intermountain Power Service Corporation
Los Angeles Department of Water and Power

These tests were conducted to evaluate overall generating station and equipment performance. General Electric test data were used in determining the net turbine heat rate, condenser, feedwater heater, boiler feed pump, and boiler feed pump turbine performance.

In addition to determining acceptability of equipment performance, the tests provide IPSC with bench mark data. Subsequent periodic tests on the unit can be compared with this bench mark data to reveal equipment wear or deterioration of performance from other causes.

2.0 SUMMARY AND CONCLUSIONS

2.1 TURBINE-GENERATOR

The turbine-generator heat rate at 820 MW was determined by straight line interpolation between the corrected test heat rates for the third and fourth valve point tests and subtracting the differential heat rate between the straight line and design curve, as per the contract. This resulted in a heat rate of 7,769 BTU/KWHR, by the customer definition (one percent condensate makeup), and is 0.7 percent better than the manufacturer's guarantee heat rate of 7,826 BTU/KWHR. (Heat rates include power to booster boiler feed pumps.)

2.2 STEAM GENERATOR

The steam generator efficiency test was postponed after one set of data was obtained and it was determined that the boiler was not ready for testing. From the data obtained, corrected only for air inlet temperature and moisture in the air, the efficiency was 86.86 percent. The difference between the test efficiency and the guaranteed efficiency of 88.57 percent (by heat loss method), was largely due to off-design excess air, exit flue gas temperature, and hydrogen content of the fuel, which increased losses 0.2 percent, 0.7 percent, and 0.98 percent respectively.

2.3 BOILER FEED PUMP TURBINES

One boiler feed pump turbine was tested (1A), as per the contract. The corrected steam rate at rated capacity was determined to be 9.57 LB/HP-HR, which is 3.8 percent higher than the guaranteed steam rate of 9.217 LB/HP-HR. Even after applying the contract test uncertainly allowance of 1.85 percent, the turbine will not meet the guarantee. However, some doubt exists about the validity of the data obtained from the torque monitoring system, which makes the results inconclusive.

2.4 BALANCE OF PLANT

Data obtained from the above tests, along with concurrent station instrument data, were used to evaluate the performance of various equipment in the plant cycle, and to determine what equipment needs additional testing. The results are summarized as follows.

2.4.1 Surface Condenser

While the hood pressures were excessive in all cases, the performance factors of heat transfer coefficient and cleanliness were deficient only in hood C (HP Condenser 1A). It has since been found that a plug missing from the steam seal three way diverting valve was causing air infiltration into this hood. It is most likely that proper cooling tower performance and elimination of air infiltration into the condenser will produce expected hood pressures.

2.4.2 Feedwater Heaters

All of the feedwater heaters with the exception of LP Heater 1A, which was affected by the air infiltration described previously had better than guaranteed subcooler approach temperature differentials and closely comparable terminal temperature differentials to guarantees.

2.4.3 Main Boiler Feed Pumps

The efficiency of the boiler feed pump associated with the tested boiler feed pump turbine was 73.82 percent as determined from the torque monitoring system data. The efficiency can also be approximated by determining the performance relative to design conditions using the affinity laws, which yields an efficiency of 79.55 percent. The test speed for the boiler feed pump turbine was significantly different from the rated speed of the pump, so corrections may have a large uncertainty. While it would appear that the guaranteed pump efficiency of 87 percent was not met, further testing at the rated pump speed is required for accurate comparison.

3.0 TEST RESULTS

3.1 GENERAL

General Electric test data, and information computer data when required, were used in the performance calculations. Test cycle heat balances, Figures 3-1 through 3-6 are based on heat balance calculations around the high-pressure heaters and deaerator, using a calibrated condensate flow section to determine boiler feedwater flow and subsequently main steam and reheat steam flows.

3.2 TURBINE-GENERATOR

The measure of the turbine generator's performance is the net turbine heat rate. The turbine-generator performance was guaranteed on a "customer definition" heat rate basis. The customer heat rate was calculated by dividing the corrected heat input by the corrected generator output.

Table 3-1 is a summary of the customer definition turbine heat rates and corrected loads. Figure 3-7 shows the turbine heat rates determined from the tests and manufacturer's predicted heat rates. The test heat rates were corrected using ASME PTC 6.0 Group I and Group II corrections. The Group II correction curves are included in Section 6.0 of this report.

The test net heat rate is calculated by dividing the total heat input by the net generation. Figure 3-8 is a graphical representation of the test net heat rate versus net generation. A summary of the test net heat rates is shown in Table 3-2.

Turbine stage efficiencies were determined by dividing the available energy in the steam by the isentropic expansion heat content of the steam. Table 3-3 shows a summary of the stage efficiencies for each test.

A Willins Curve, throttle flow versus gross generation, is shown on Figure 3-9. Table 3-4 shows a summary of the throttle flows and gross generator output.

3.3 CONDENSER

The condenser heat transfer coefficient is calculated by dividing the heat rejected from the condensate by the area of the surface condenser and the log mean temperature difference of the circulating water. This value is then corrected for circulating water inlet temperature. The cleanliness factor is found by comparing the actual corrected heat transfer coefficient with a manufacturer defined minimum cleanliness heat transfer coefficient.

The heat transfer coefficient and cleanliness factor for each condenser hood was calculated for the VWO tests and are shown on Table 3-5 as a comparative tabulation of condenser performance.

3.4 FEEDWATER HEATERS

Heater performance is generally measured by the terminal difference and subcooler approach temperatures. Graphical representations of the heater performances which illustrate terminal difference and subcooler approach temperatures varying with load are shown in Figures 3-10 through 3-20.

Table 3-6 shows the comparative closed feedwater heater performance. A summary of the terminal difference and subcooler approach temperatures is shown in Table 3-7.

3.5 BOILER FEED PUMP TURBINES

One boiler feed pump turbine (1A) was tested in accordance with the contract. The boiler feed pump turbine efficiency is calculated by dividing the available energy of the steam through the turbine by the isentropic expansion heat content of the steam. The available energy of the steam is calculated by dividing the measured horsepower output of the turbine by the corrected steam flow rate and appropriate conversion factors. The steam flow is corrected for throttle temperature, throttle pressure, turbine speed, and turbine back pressure. The steam rate is calculated by dividing the corrected steam flow rate by the measured horsepower output of the turbine.

Table 3-8 gives comparative performance for the tests with throttle flow closest to that of guarantee (Tests 4 and 7). Table 3-9 is a summary of efficiency and steam rate for the tests.

3.6 BOILER FEED PUMPS

One boiler feed pump was tested for efficiency. Boiler feed pump efficiency is calculated by multiplying the developed head by the volumetric flow and specific gravity of the water pumped and dividing by the horsepower input and appropriate conversion factors. Relative performance is calculated by dividing the corrected developed head by the expected developed head. Expected developed head is a function of corrected volumetric flow.

Table 3-10 is a comparative tabulation of boiler feed pump performance. Table 3-11 provides a summary of the pump efficiency and relative performance for the tests.

3.7 FEEDWATER FLOW NOZZLE VERSUS CONDENSATE FLOW NOZZLE

ASME PTC 6.1 provides an alternative testing procedure to determine turbine heat rate. Instead of measuring the condensate flow and calculating the feedwater flow, a flow element in the feedwater line after the final feedwater heater is used to directly compute the feedwater flow. It has been shown that this is an acceptable, less expensive method, due to fewer, less precise measurements.

Test heat rates for the full ASME test and for the feedwater flow nozzle measurements were calculated and are shown in Table 3-12. For most of the tests, the difference between the heat rates determined from the feedwater flow nozzle as compared to the heat rates determined from the condensate flow nozzle are very close to the one-third percent uncertainty expected in PTC 6.1.

TABLE 3-1. ONE PERCENT MAKEUP CORRECTED HEAT RATES

	CORRECTED HEAT RATE, BTU/KWHR	CORRECTED LOAD, KW
VWO	7,750	876,492
3rd VP	7,784	799,318
2nd VP	7,941	600,837

INTERPOLATED HEAT RATE
a 820 MW = 7,769 BTU/KWHR

GUARANTEED HEAT RATE
a 820 MW = 7,826 BTU/KWHR

* Includes booster boiler feed pump power.

TABLE 3-2. TEST NET HEAT RATE VERSUS NET LOAD

TEST	TEST HR, BTU/KWHR	NET LOAD, KW MEASURED
3	8,253	831,228
6	8,320	813,163
4	8,302	751,487
7	8,351	736,550
5	8,450	561,441
8	8,515	552,776

TABLE 3-3. TURBINE EFFICIENCY

TEST	HIGH PRESSURE, PERCENT	INTERMEDIATE PRESSURE, PERCENT	LOW PRESSURE, PERCENT
3	87.96	91.94	94.60
6	87.34	92.55	95.08
4	86.10	92.73	93.61
7	86.20	92.64	94.04
5	80.71	92.51	93.93
8	80.96	92.12	94.43

TABLE 3-4. THROTTLE FLOW VERSUS GROSS GENERATION

TEST	GROSS GENERATION, KW	THROTTLE FLOW, LB/HR
3	871,725	6,326,796
6	860,177	6,219,100
4	791,473	5,661,433
7	778,625	5,546,060
5	596,565	4,079,800
8	590,648	4,056,820

TABLE 3-5. COMPARATIVE CONDENSER PERFORMANCE

	TEST *	GUARANTEE
PRESSURE (IN HG)		
HOOD A	4.18	3.36
HOOD B	3.65	2.80
HOOD C	3.65	2.34
HEAT TRANSFER COEFFICIENT (BTU/HR-FT^2-F)		
HOOD A	717.09	558.8
HOOD B	577.08	539.3
HOOD C	397.07	539.3
CLEANLINESS FACTOR (PERCENT)		
HOOD A	118.90	85
HOOD B	95.5	85
HOOD C	65.72	85

*VWO

TABLE 3-6. COMPARATIVE FEEDWATER HEATER PERFORMANCE

LOW-PRESSURE HEATERS

HEATERS 1A, 1B, AND 1C

	DESIGN	TEST
CONDENSATE FLOW, LB/HR	5,254,771	4,575,070
SHELL PRESSURE, PSIA	4.51	5.29
STEAM TO HEATER, LB/HR	169,144	91,168
ENTHALPY OF STEAM, BTU/LB	1,100.9	1,090
TERMINAL DIFFERENCE, F	2.0	6.91
SUBCOOLER APPROACH, F	5.0	4.52
SUBCOOLER FLOW, LB/HR	920,818	598,157

HEATER 2

	DESIGN	TEST
CONDENSATE FLOW, LB/HR	5,254,771	4,575,070
SHELL PRESSURE, PSIA	10.7	11.19
STEAM TO HEATER, LB/HR	178,238	154,582
ENTHALPY OF STEAM, BTU/LB	1,142.5	1,161.3
TERMINAL DIFFERENCE, F	2.0	1.55
SUBCOOLER APPROACH, F	10	4.25
SUBCOOLER FLOW, LB/HR	573,462	433,510

HEATER 3

	DESIGN	TEST
CONDENSATE FLOW, LB/HR	6,127.017	4,575,070
SHELL PRESSURE, PSIA	37.7	38.9
STEAM TO HEATER, LB/HR	378,723	291,633
ENTHALPY OF STEAM, BTU/LB	1,236.2	1,243.2
TERMINAL DIFFERENCE, F	2.0	-1.03
SUBCOOLER APPROACH, F	10	8.70
SUBCOOLER FLOW, LB/HR	194,754	141,877

TABLE 3-6. COMPARATIVE FEEDWATER HEATER PERFORMANCE (Continued)

HEATER 4

	DESIGN	TEST
CONDENSATE FLOW, LB/HR	6,127,017	4,575,070
SHELL PRESSURE, PSIA	63.2	64.7
STEAM TO HEATER, LB/HR	194,754	141,877
ENTHALPY OF STEAM, BTU/LB	1,282.3	1,289.6
TERMINAL DIFFERENCE, F	2.0	-0.27
SUBCOOLER APPROACH, F	10	6.75
SUBCOOLER FLOW, LB/HR	---	---

HIGH-PRESSURE HEATERS

HEATERS 6A AND 6B

	DESIGN	TEST
FEEDWATER FLOW, LB/HR	6,513,490	6,203,725
SHELL PRESSURE, PSIA	230.6	232.4
STEAM TO HEATER, LB/HR	239,944	240,042
ENTHALPY OF STEAM, BTU/LB	1,419.8	1,423.8
TERMINAL DIFFERENCE, F	-2.0	-2.15
SUBCOOLER APPROACH, F	10	8.21
SUBCOOLER FLOW, LB/HR	1,203,812	1,144,596

HEATERS 7A AND 7B

	DESIGN	TEST
FEEDWATER FLOW, LB/HR	6,513,490	6,203,725
SHELL PRESSURE, PSIA	584.3	570.8
STEAM TO HEATER, LB/HR	610,344	547,145
ENTHALPY OF STEAM, BTU/LB	1,306.6	1,306.4
TERMINAL DIFFERENCE, F	-1.0	-0.26
SUBCOOLER APPROACH, F	10	7.30
SUBCOOLER FLOW, LB/HR	593,470	597,451

TABLE 3-6. COMPARATIVE FEEDWATER HEATER PERFORMANCE (Continued)

HEATER 8A AND 8B

	DESIGN	TEST
FEEDWATER FLOW, LB/HR	6,513,490	6,203,725
SHELL PRESSURE, PSIA	1,061	1,081.8
STEAM TO HEATER, LB/HR	593,470	597,451
ENTHALPY OF STEAM, BTU/LB	1,369.2	1,381.5
TERMINAL DIFFERENCE, F	-2.0	-1.40
SUBCOOLER APPROACH, F	10	8.74
SUBCOOLER FLOW, LB/HR	---	---

TABLE 3-7. FEEDWATER HEATER TEST RESULTS

LOW-PRESSURE HEATERS

	HEATER 1A	HEATER 1B	HEATER 1C	HEATER 1
TEST	TD	TD	TD	SA
3	20.80	3.49	3.26	4.46
6	9.62	3.33	3.26	4.58
4	13.75	3.61	3.50	4.31
7	20.18	3.53	3.46	3.84
5	5.36	4.28	4.28	1.65
8	5.03	4.14	4.03	3.04

HEATER 2

TEST	TD	SA
3	1.57	6.6
6	1.53	1.90
4	1.31	6.18
7	1.59	5.82
5	1.01	-8.63
8	1.28	3.97

HEATER 3

TEST	TD	SA
3	-0.95	8.80
6	-1.10	8.60
4	-0.77	8.15
7	-0.52	8.21
5	-1.48	6.85
8	-1.50	6.66

TABLE 3-7. FEEDWATER HEATER TEST RESULTS (Continued)

HEATER 4

TEST	TD	SA
3	-0.30	6.80
6	-0.23	6.70
4	-0.50	6.72
7	-0.58	7.12
5	-1.11	5.88
8	-1.10	6.20

HIGH-PRESSURE HEATERS

	HEATER 6A		HEATER 6B	
TEST	TD	SA	TD	SA
3	-2.13	8.80	-1.63	8.40
6	-2.72	8.04	-2.09	7.60
4	-3.03	7.22	-2.62	7.32
7	-3.38	6.91	-2.79	6.66
5	-5.16	5.56	-4.65	5.38
8	-5.05	5.38	-4.47	5.17

	HEATER 7A		HEATER 7B	
TEST	TD	SA	TD	SA
3	-0.18	7.80	0.10	7.20
6	-0.60	7.40	-0.33	6.80
4	-1.04	6.79	-0.72	6.17
7	-1.38	6.50	-1.46	6.69
5	-2.39	4.62	-2.26	4.49
8	-2.55	4.39	-2.80	4.75

TABLE 3-7. FEEDWATER HEATER TEST RESULTS (Continued)

HIGH-PRESSURE HEATERS

	HEATER 8A		HEATER 8B	
TEST	TD	SA	TD	SA
3	-0.60	10.40	-1.45	7.90
6	-1.35	9.50	-2.18	7.15
4	-2.56	8.55	-3.11	6.44
7	-3.40	8.04	-3.48	6.26
5	-5.47	5.59	-5.64	3.99
8	-6.11	5.31	-5.84	3.86

TABLE 3-8. COMPARATIVE BOILER FEED PUMP TURBINE PERFORMANCE

	GUARANTEE	TEST*
THROTTLE FLOW, LB/HR	99,526	117,170
STEAM RATE, LB/HP-HR	9.217	9.57
EFFICIENCY, PERCENT	85.5	83.40
THROTTLE PRESSURE, PSIA	111	103.9
THROTTLE TEMPERATURE, F	633	620.1
EXHAUST PRESSURE, IN HGA	4.0	3.77
TURBINE SPEED, RPM	5,100	5,086

*TEST 4 AND 7

TABLE 3-9. BOILER FEED PUMP TURBINE

TEST	BFPT 1A EFFICIENCY, %	STEAM RATE (LB/HP-HR)
3	81.04	9.88
6	83.42	9.55
4	81.87	9.742
7	84.92	9.407
5	81.37 (UC)	9.855 (UC)
8	84.85 (UC)	9.573 (UC)

UC - Uncorrected

TABLE 3-10. COMPARATIVE BOILER FEED PUMP PERFORMANCE

	GUARANTEE	TEST*
CAPACITY, GPM	7,700	7,546
TOTAL HEAD, FEET	8,000	7,569
EFFICIENCY, PERCENT	87.0	73.82
BRAKE HORSEPOWER, BHP	15,562	15,045
PUMP SPEED, RPM	5,750	5,374
RELATIVE PERFORMANCE	1.0	0.928

*VWO

TABLE 3-11. TURBINE DRIVEN BOILER FEED PUMPS

TEST	BFP 1A EFFICIENCY, %	RELATIVE PERFORMANCE
3	73.67	0.921
6	73.96	0.935
4	75.31	0.934
7	73.56	0.939
5	75.65	0.957
8	72.69	0.963

TABLE 3-12. TEST HEAT RATE

TEST	FEEDWATER NOZZLE BTU/KWHR	CONDENSATE NOZZLE BTU/KWHR	ERROR, %
3	7,918	7,870	0.60
6	7,880	7,865	0.19
4	7,911	7,883	0.35
7	7,877	7,900	0.29
5	7,981	7,953	0.35
8	7,870	7,969	1.25

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ARRANGEMENT IS SCHEMATIC ONLY

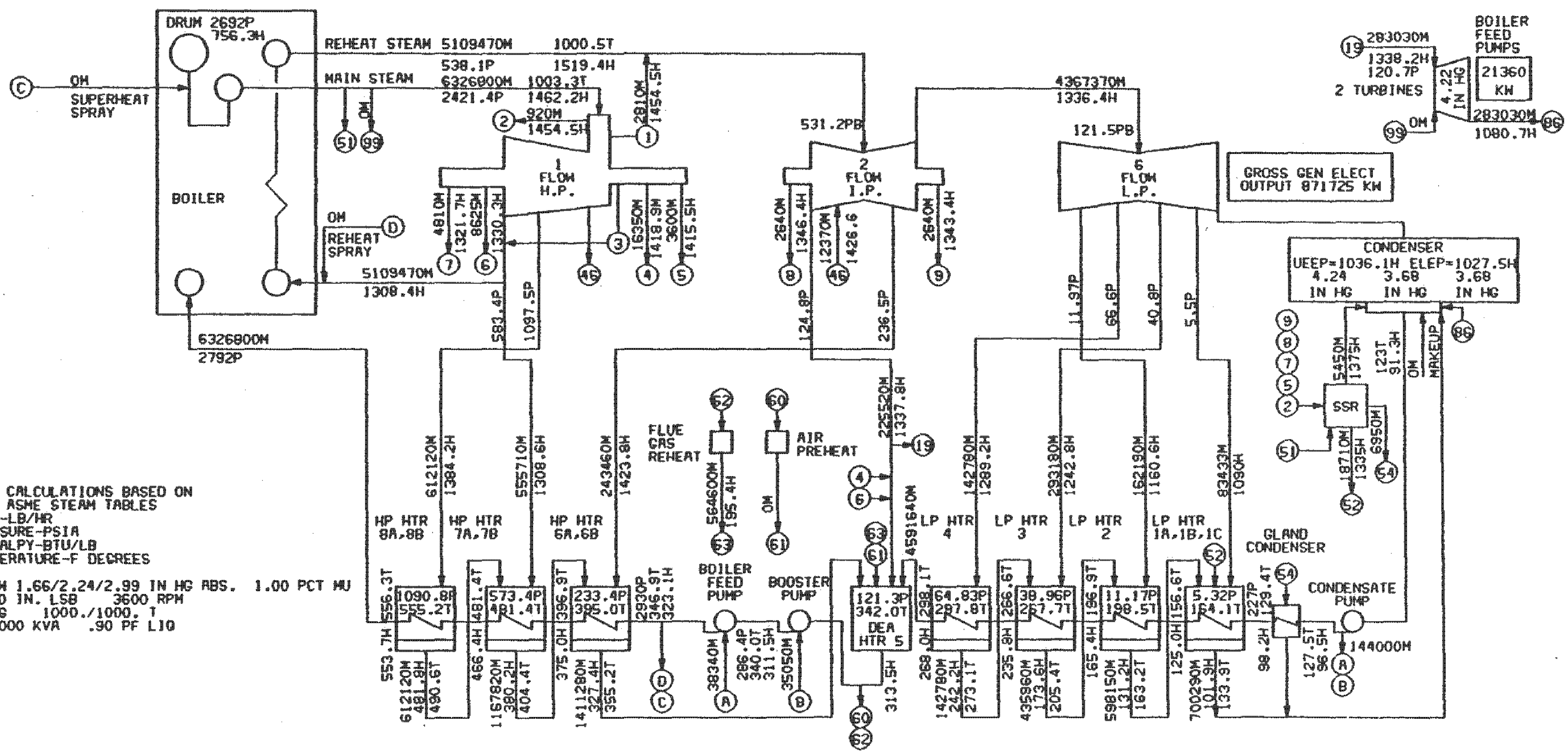


FIGURE 3-1

LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

TEST HEAT RATE = $\frac{6326796(1462.2-553.7)+6288746(1.45)+4735642(96.5-91.3)+5109470(1519.4-1308.4)+6327(756.3-553.7)}{871725KW}$ = 7870 $\frac{BTU}{KW\ HR}$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7745 $\frac{BTU}{KW\ HR}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 3 - VWO HEAT BALANCE

IP14_000531

ARRANGEMENT IS SCHEMATIC ONLY

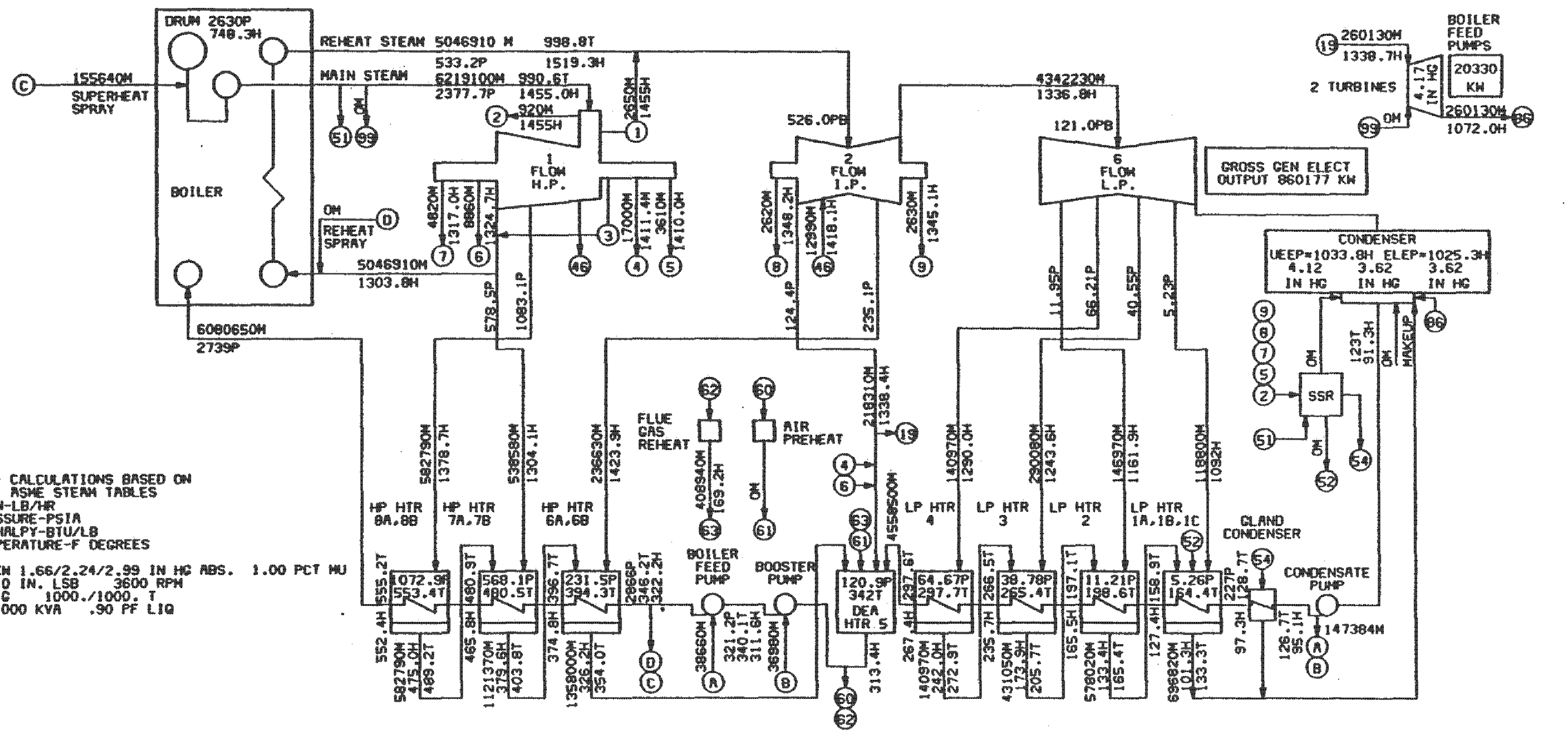


FIGURE 3-2

LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

$$\text{TEST HEAT RATE} = \frac{6063454(1455.0-552.4)+155640(1455.0-322.2)+6041992(1.45)+4705886(95.1-91.3)+5046910(1519.3-1303.8)+6219(748.3-552.4)}{860177\text{KW}} = 7864 \frac{\text{BTU}}{\text{KW HR}}$$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE $= 7755 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 6 - VWO HEAT BALANCE

ARRANGEMENT IS SCHEMATIC ONLY

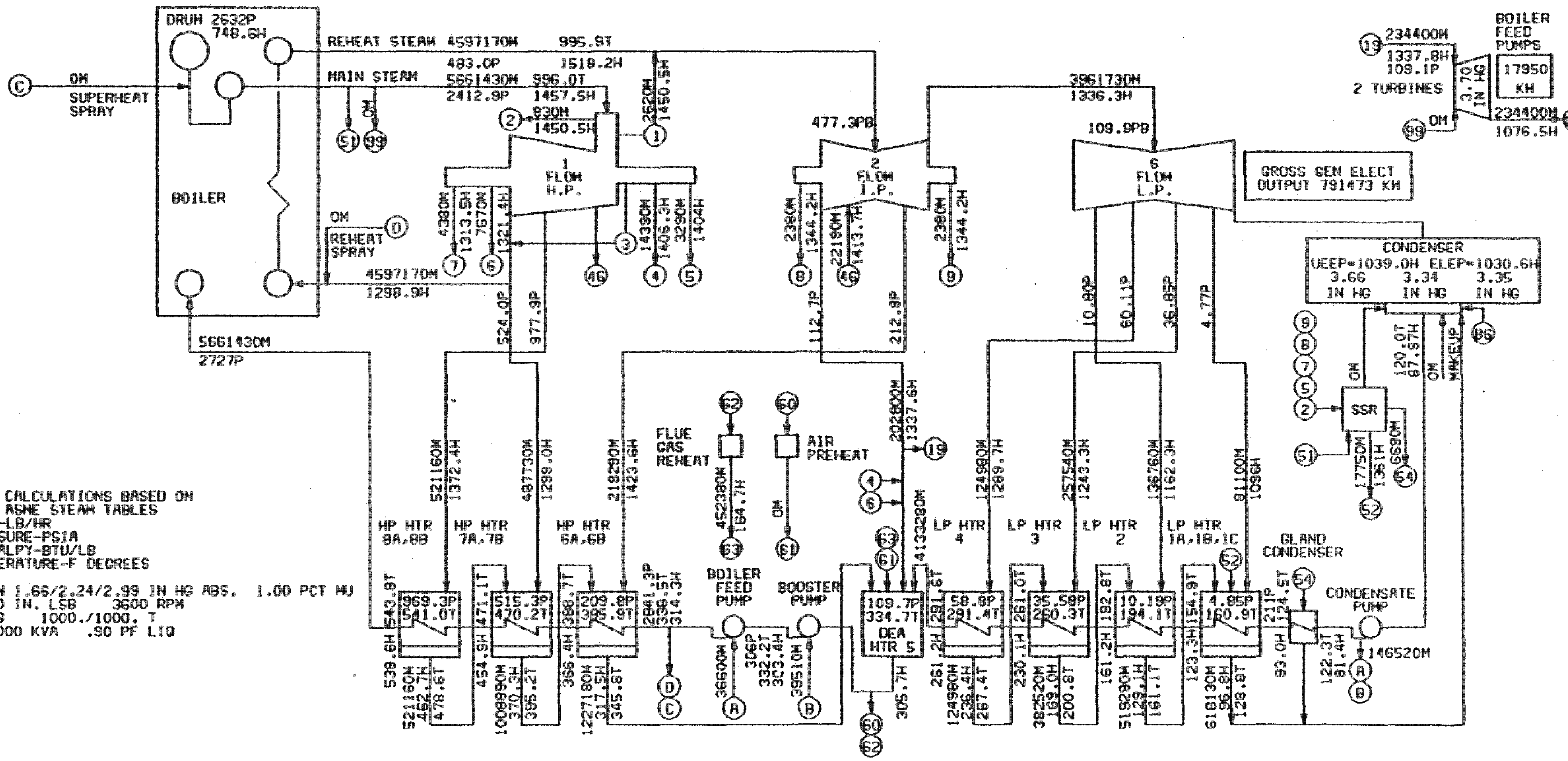


FIGURE 3-3

LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TCGF 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

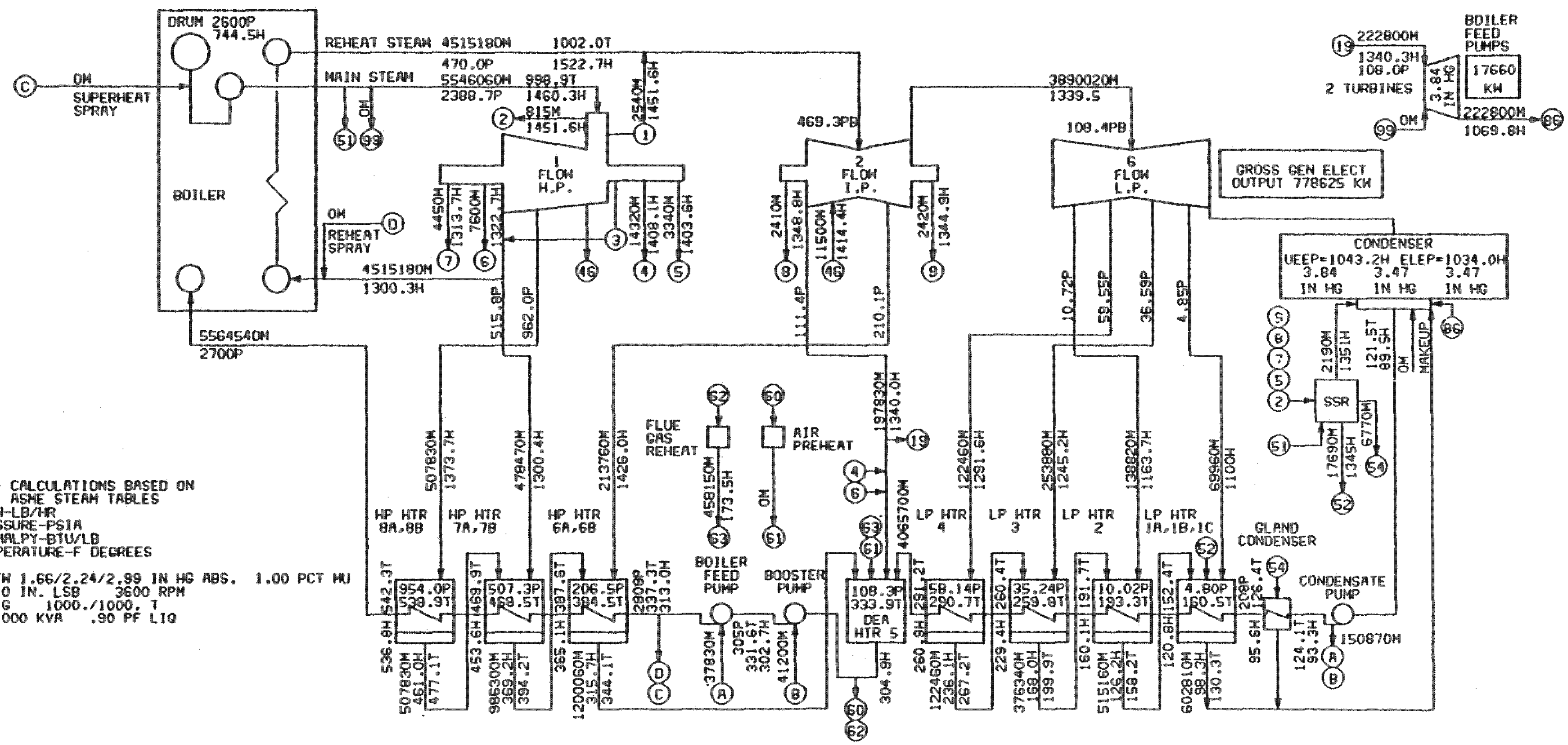
TEST HEAT RATE = $\frac{5661430(1457.5-538.6)+5624570(1.50)+4279800(91.4-88.0)+4597170(1519.2-1298.9)+5661(748.6-538.6)}{791473 \text{ KW}} = 7883 \frac{\text{BTU}}{\text{KW HR}}$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE $= 7794 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 4 - THIRD VALVE POINT HEAT BALANCE

IP14_000533

ARRANGEMENT IS SCHEMATIC ONLY



LEGEND - CALCULATIONS BASED ON ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

620000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

FIGURE 3-4

$$\text{TEST HEAT RATE} = \frac{5546060(1460.3-536.8)+5508230(1.50)+4216570(93.3-89.5)+4515180(1522.7-1300.3)+5565(744.5-536.8)}{778625\text{KW}} = 7900\ \frac{\text{BTU}}{\text{KW HR}}$$

$$\text{CORRECTED CUSTOMER DEFINED 1\% MU HEAT RATE} = 7773\ \frac{\text{BTU}}{\text{KW HR}}$$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 7 - THIRD VALVE POINT HEAT BALANCE

ARRANGEMENT IS SCHEMATIC ONLY

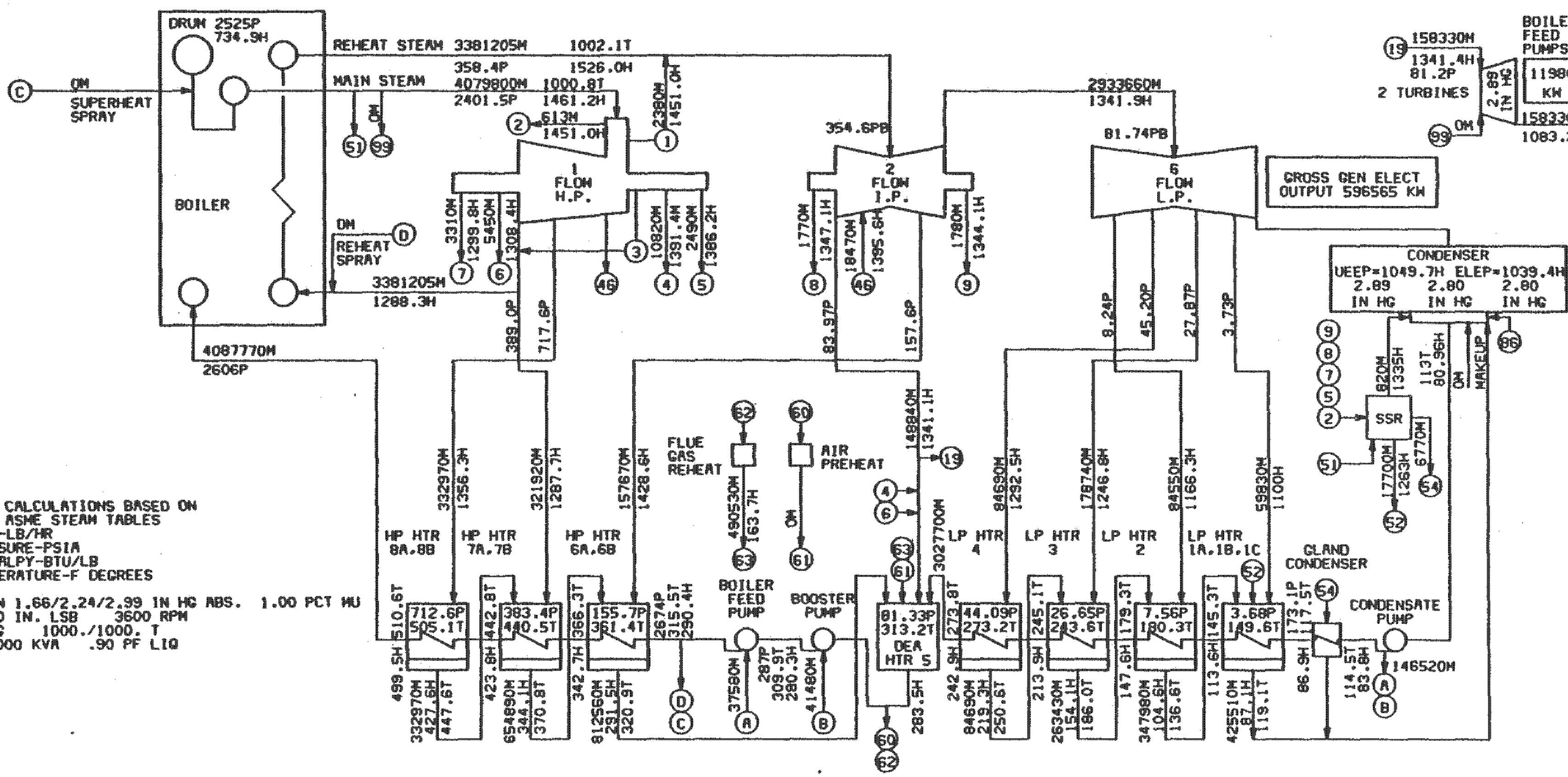


FIGURE 3-5

LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

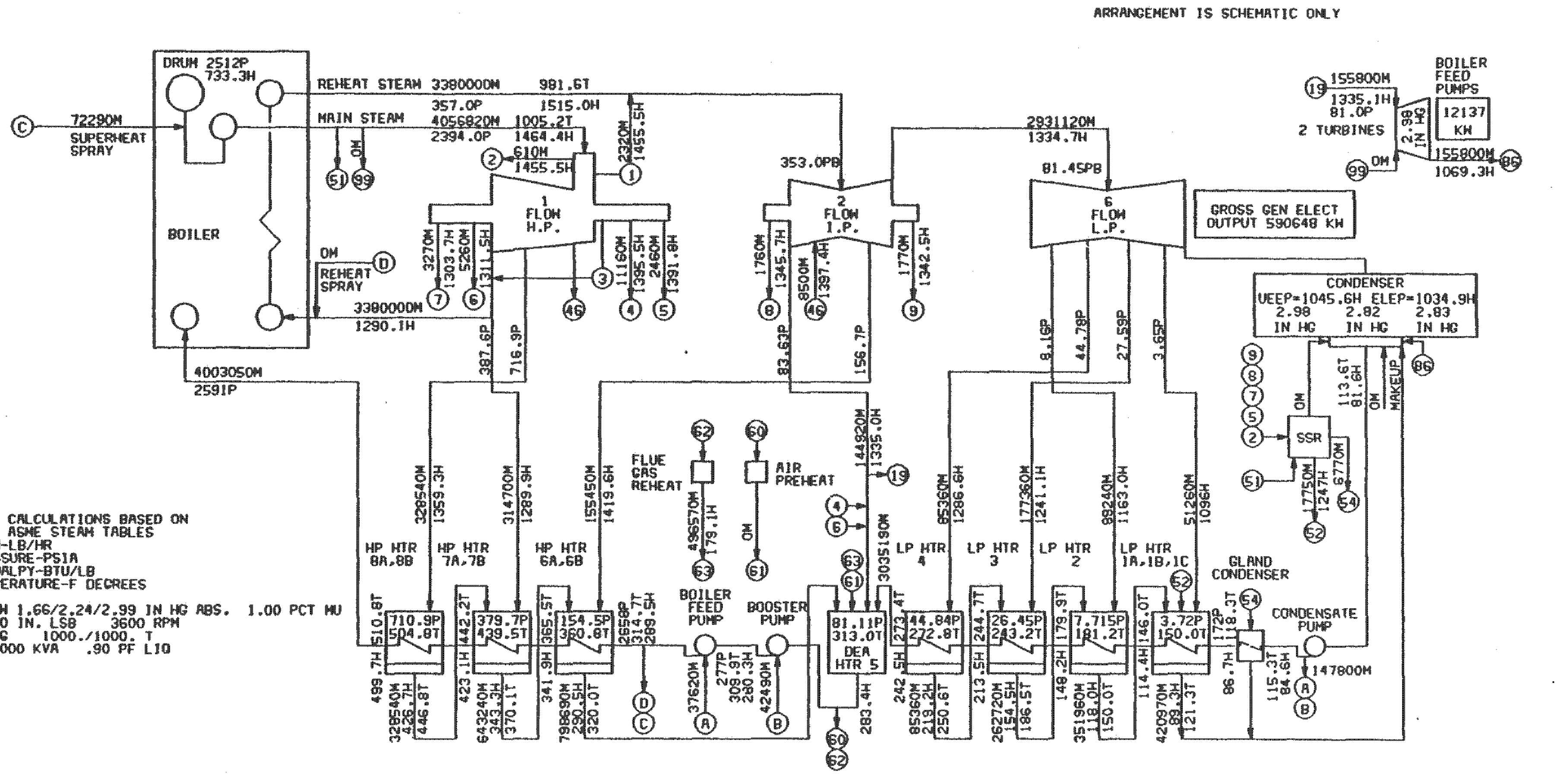
TEST HEAT RATE = $\frac{4079800(1461.2-499.5)+4050520(1.77)+3177380(83.8-81.0)+3381205(1526.0-1288.3)+4088(734.9-499.5)}{596565KW}$ = 7952 $\frac{BTU}{KW\ HR}$

CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7944 $\frac{BTU}{KW\ HR}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 5 - SECOND VALVE POINT HEAT BALANCE

IP14_000535

FIGURE 3-6



LEGEND - CALCULATIONS BASED ON
ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000./1000. T
GEN- 991000 KVA .90 PF LIQ

TEST HEAT RATE = $\frac{3984540(1464.4-499.7)+72290(1464.4-289.5)+3946910(1.77)+3182990(84.6-81.6)+3380000(1515.0-1290.1)+4075(733.3-499.7)}{590648\text{KW}} = 7969 \frac{\text{BTU}}{\text{KW HR}}$

CORRECTED CUSTOMER DEFINED
1% MU HEAT RATE $= 7937 \frac{\text{BTU}}{\text{KW HR}}$

INTERMOUNTAIN POWER AGENCY
INTERMOUNTAIN POWER PROJECT UNIT 1
TEST 8 - SECOND VALVE POINT HEAT BALANCE

IP14_000536

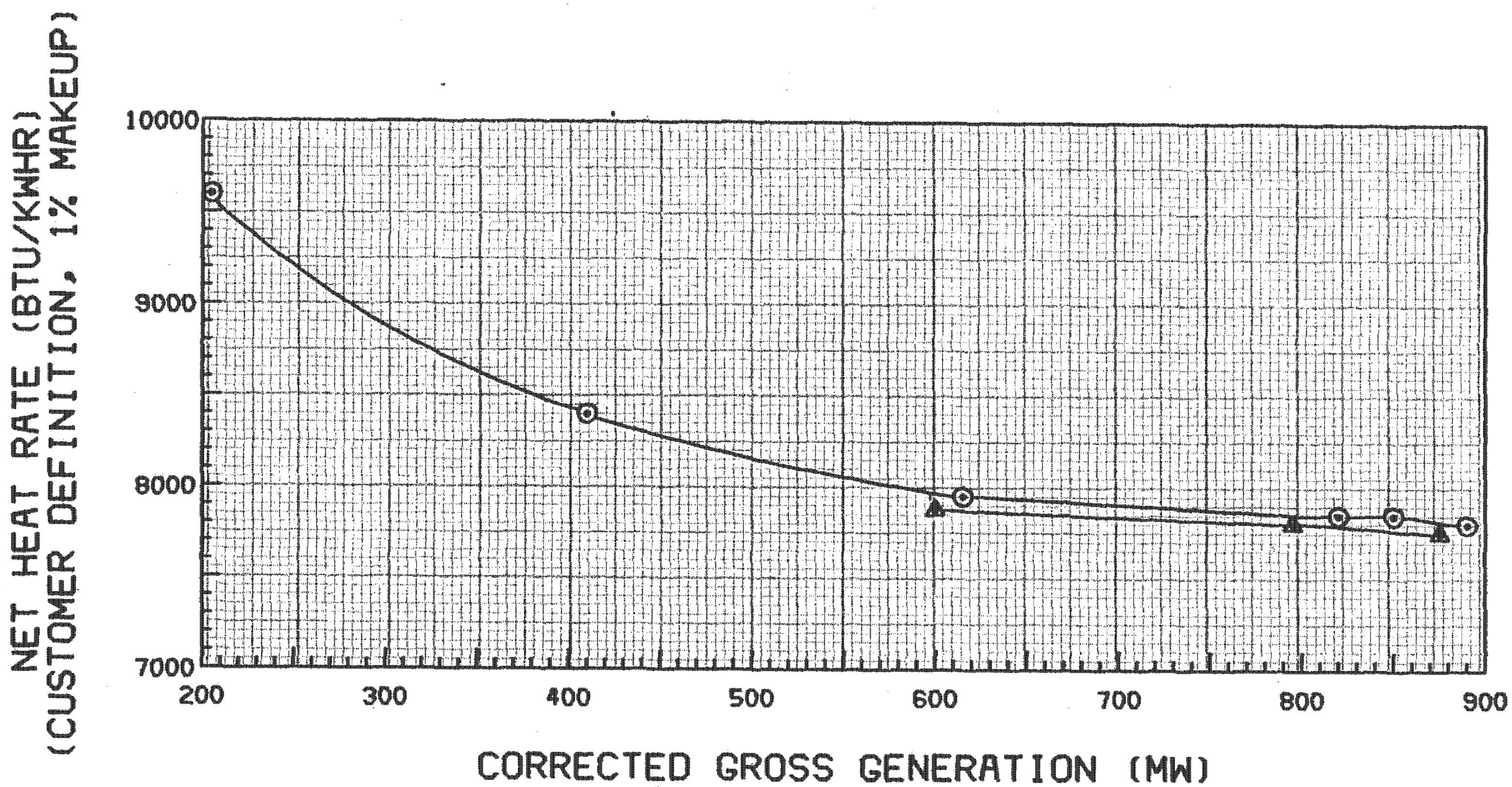


FIGURE 3-7: CORRECTED NET HEAT RATE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

KEY:
⊙ 1% MU HEAT BALANCE
▲ B&V CALCULATED HEAT RATE, 1% MU

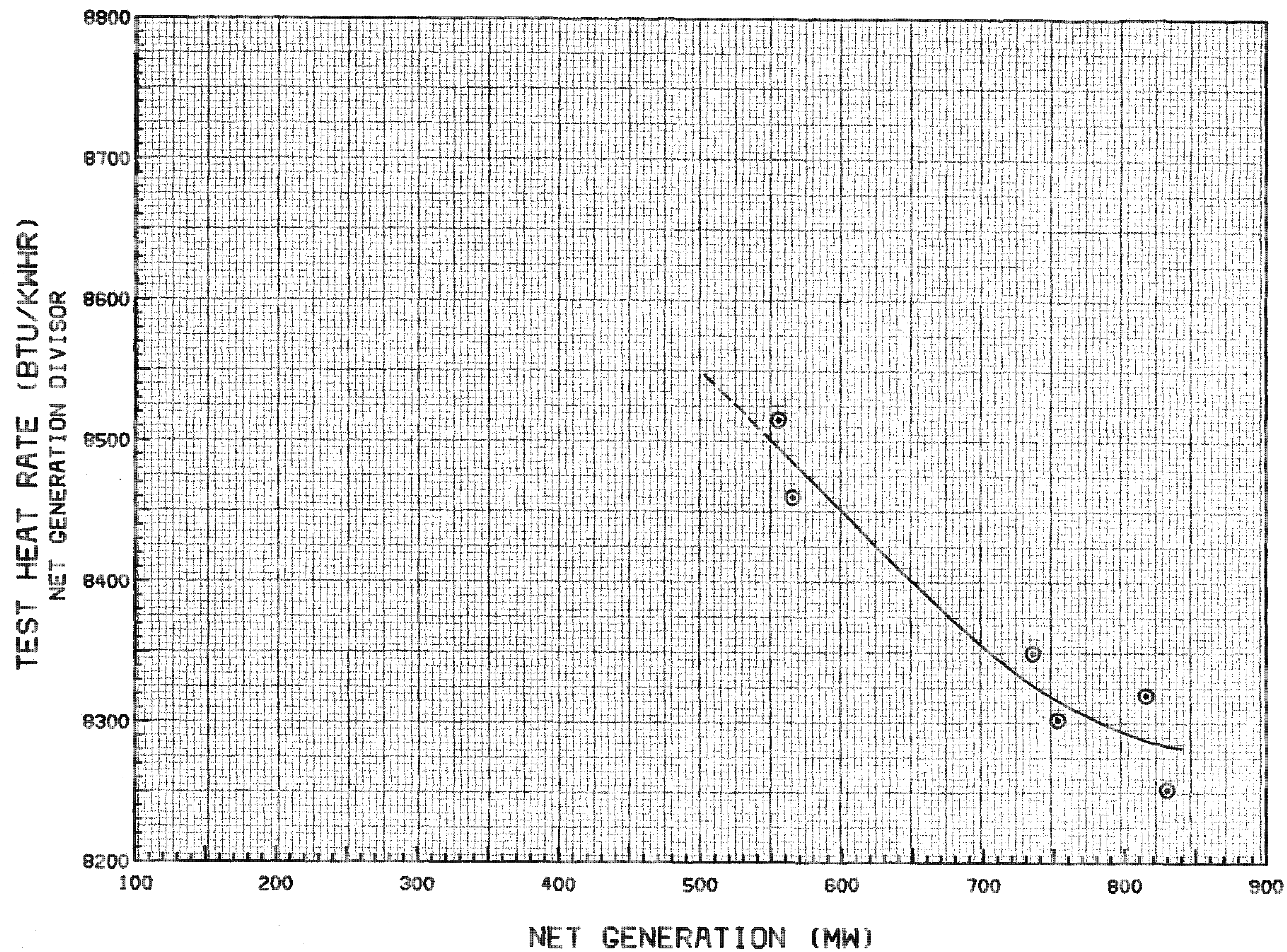


FIGURE 3-8: TEST HEAT RATE VS NET GENERATION
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

IP14_000538

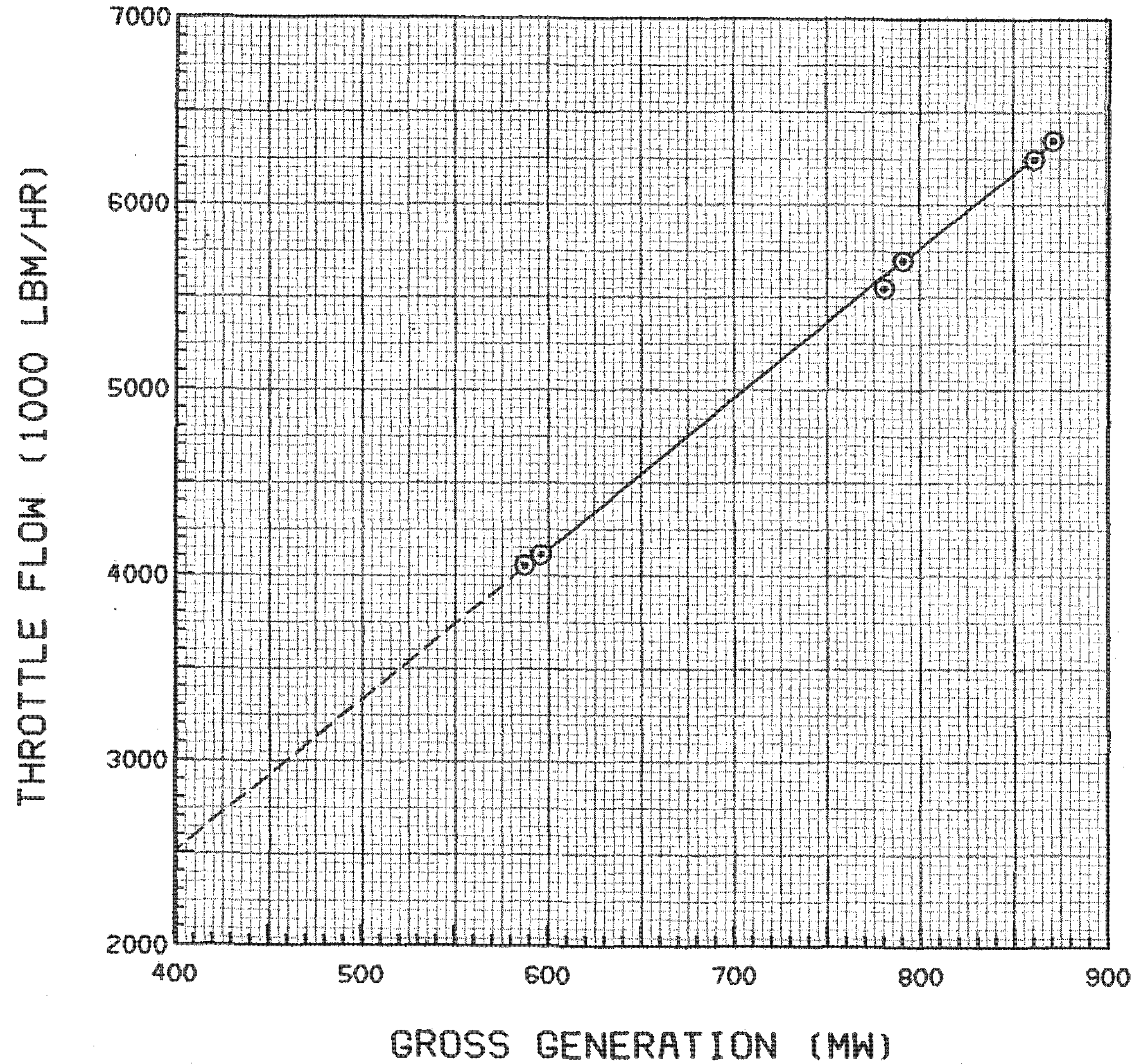


FIGURE 3-9: THROTTLE FLOW VS GROSS GENERATION
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

IP14_000539

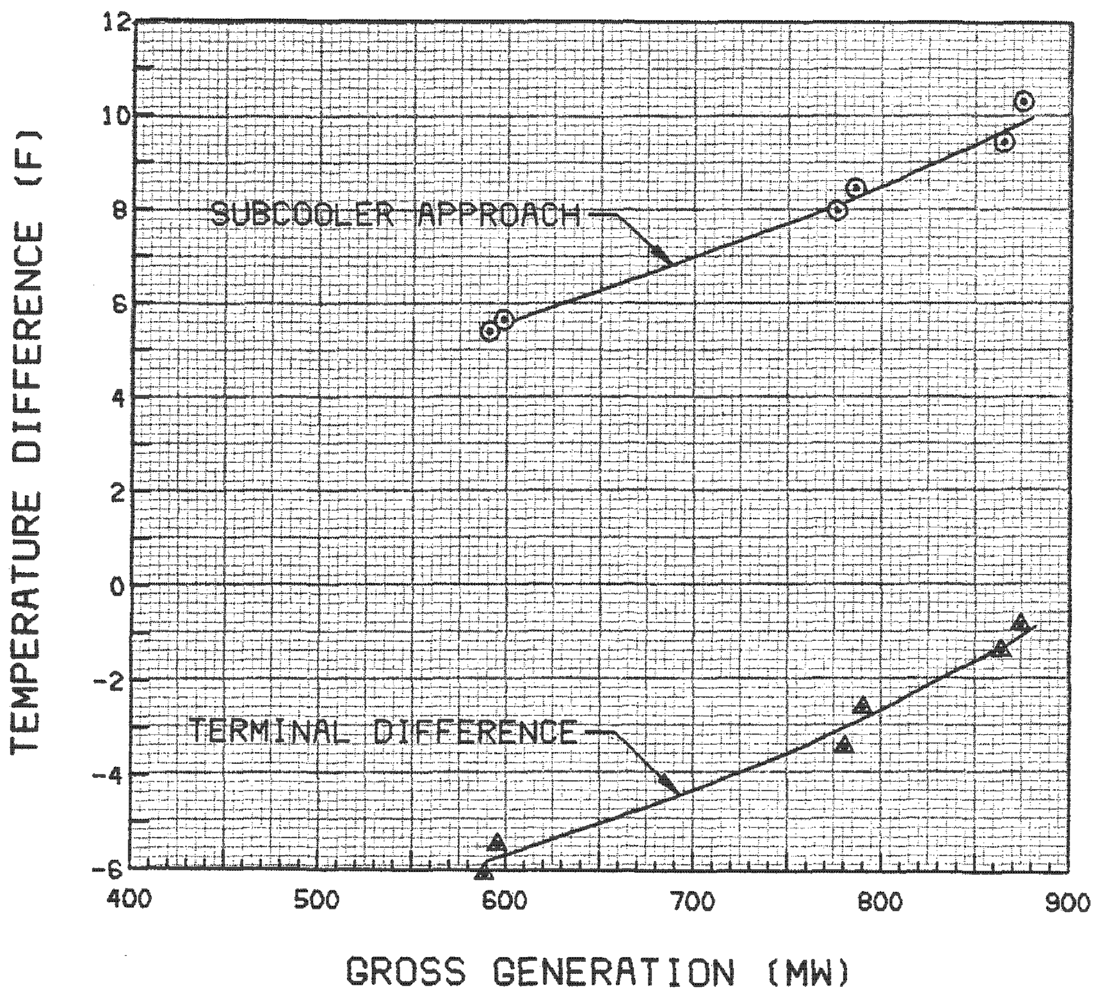


FIGURE 3-10: HEATER 8A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

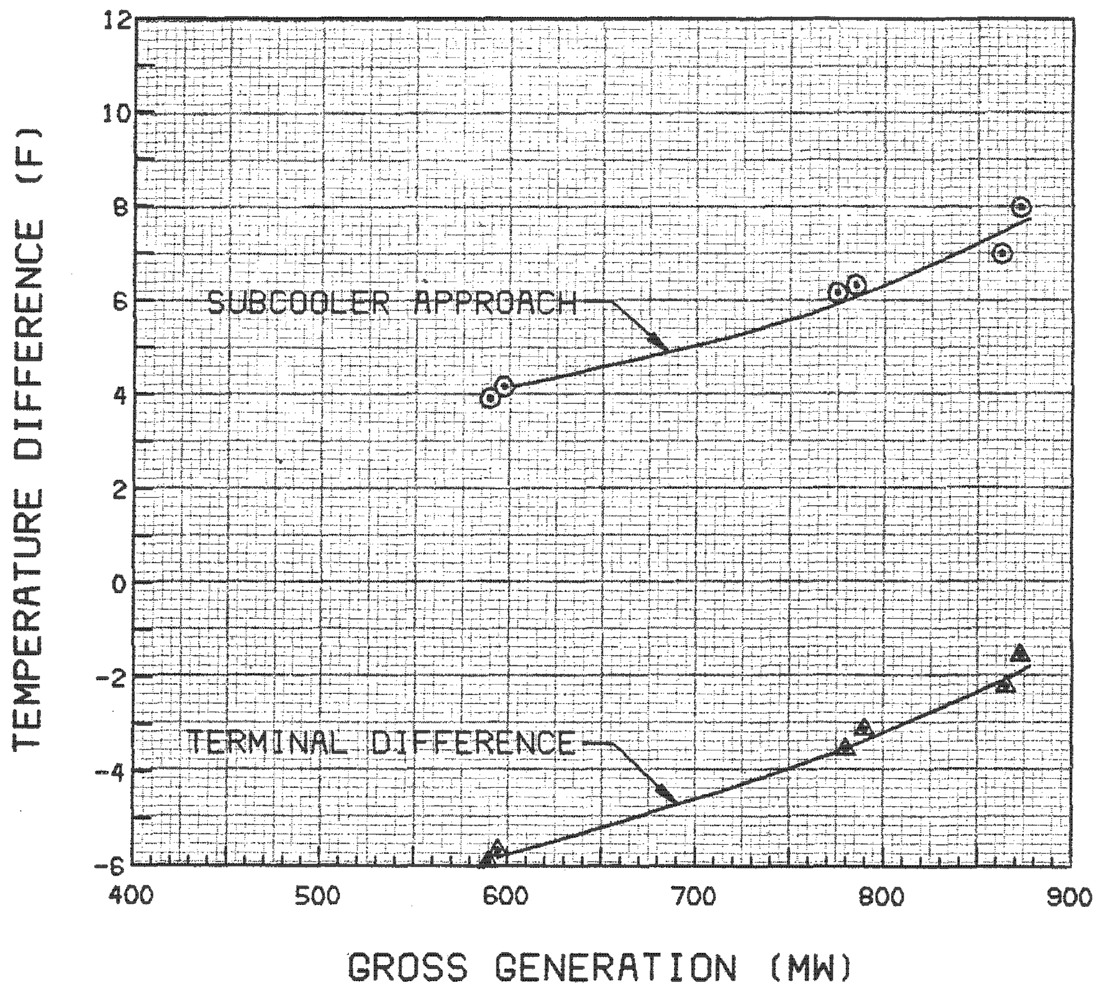


FIGURE 3-11: HEATER 8B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

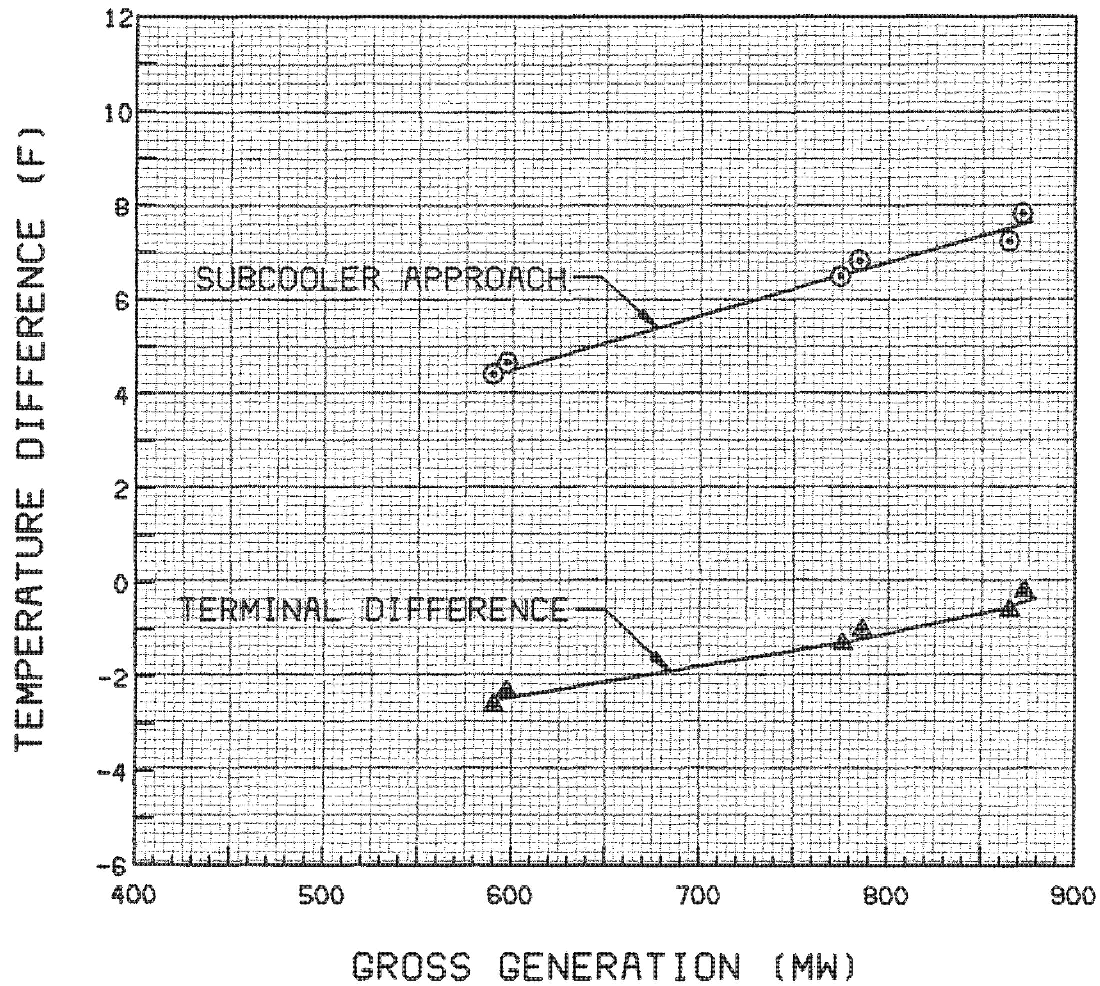


FIGURE 3-12: HEATER 7A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

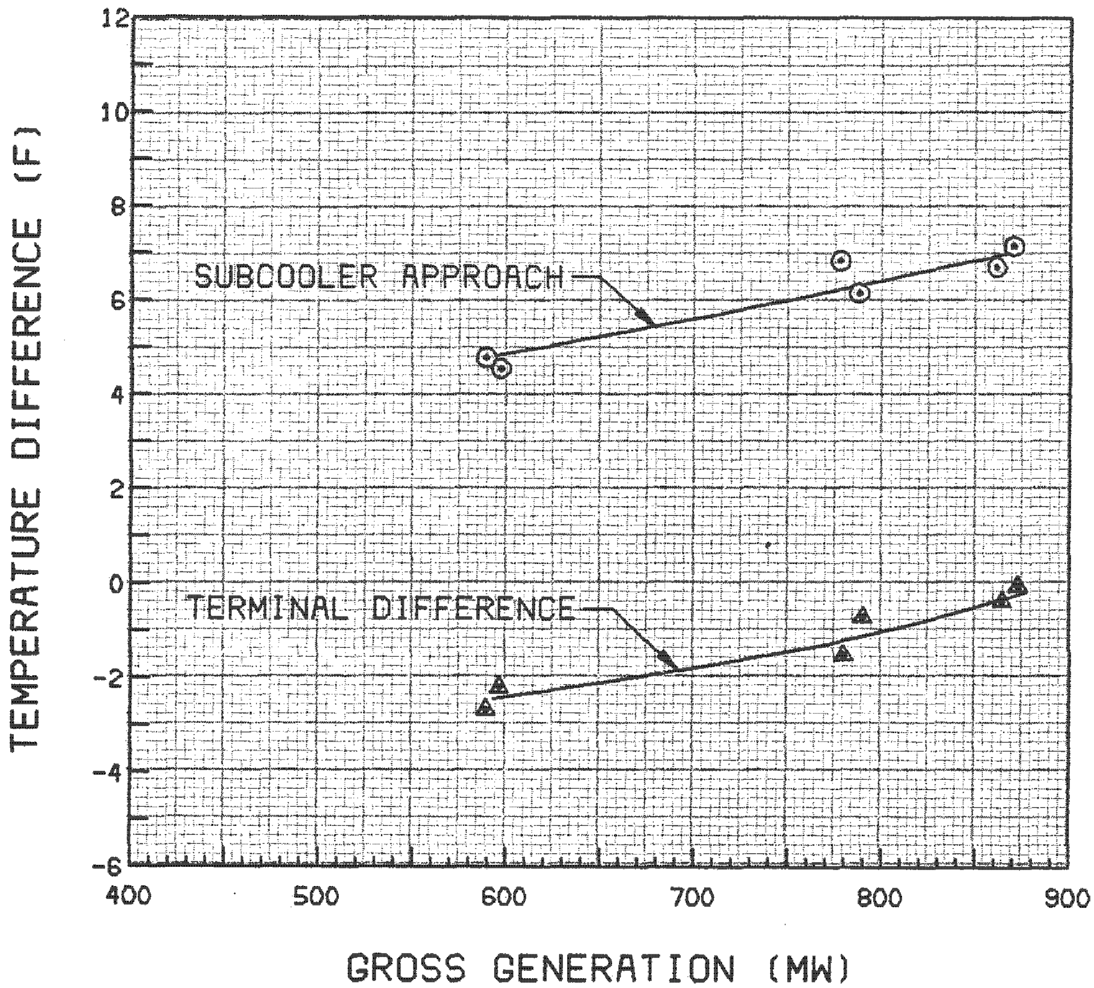


FIGURE 3-13: HEATER 7B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

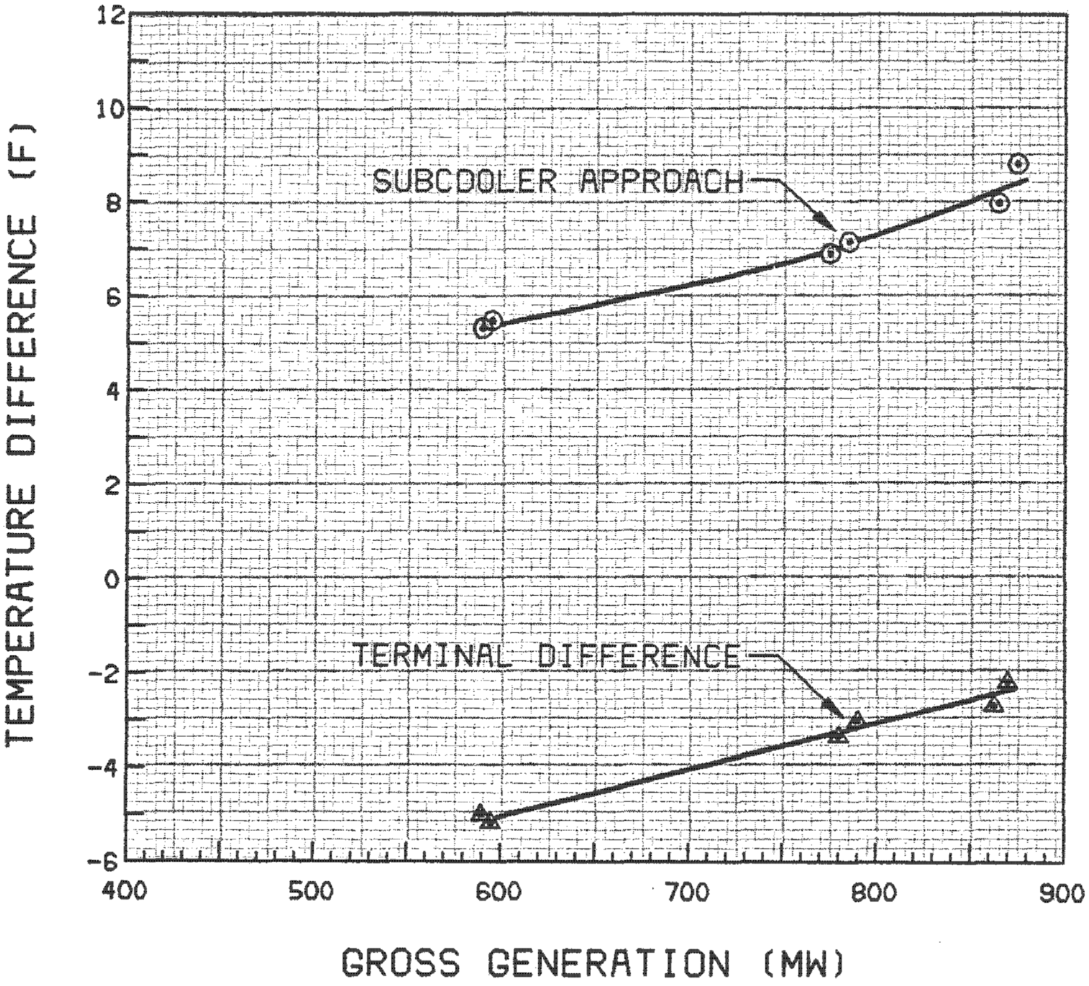


FIGURE 3-14: HEATER 6A PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

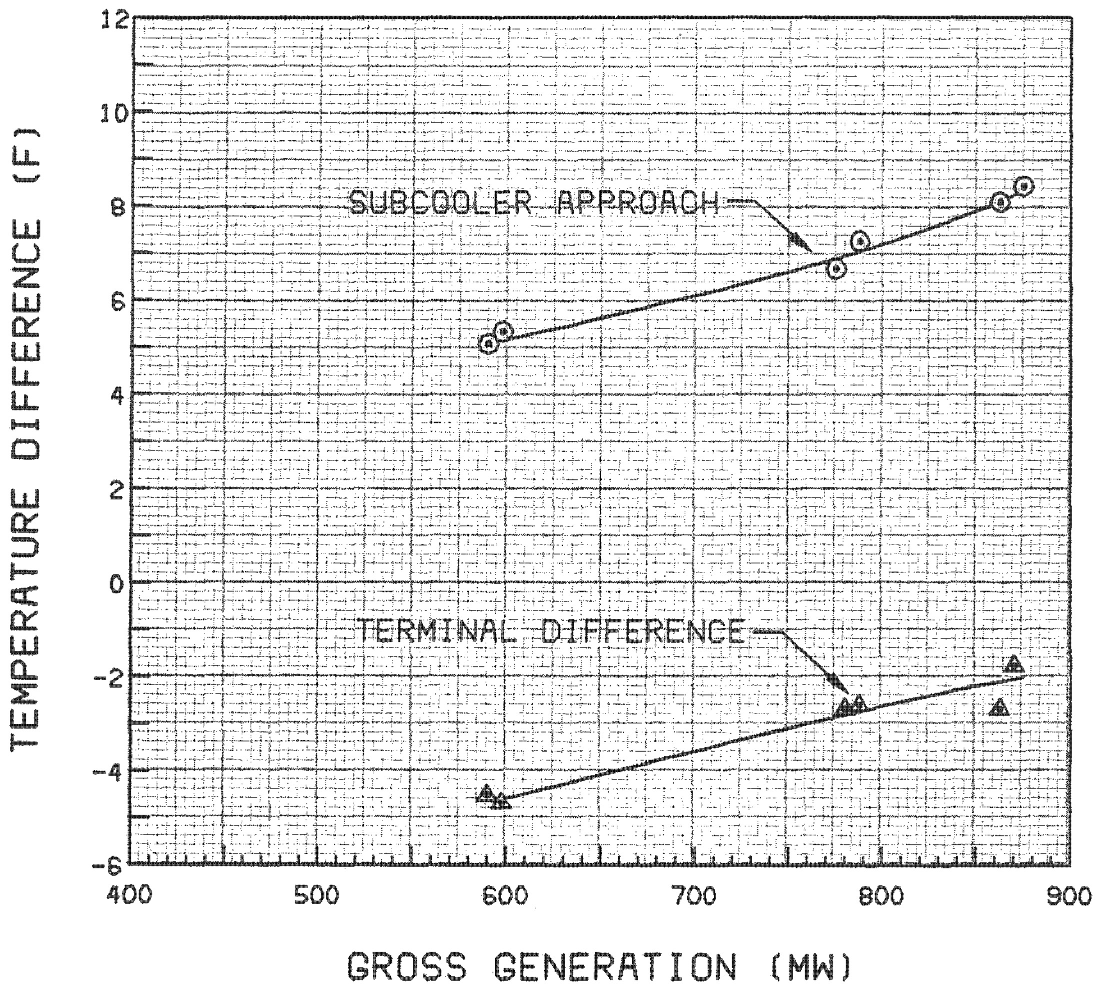


FIGURE 3-15: HEATER 6B PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

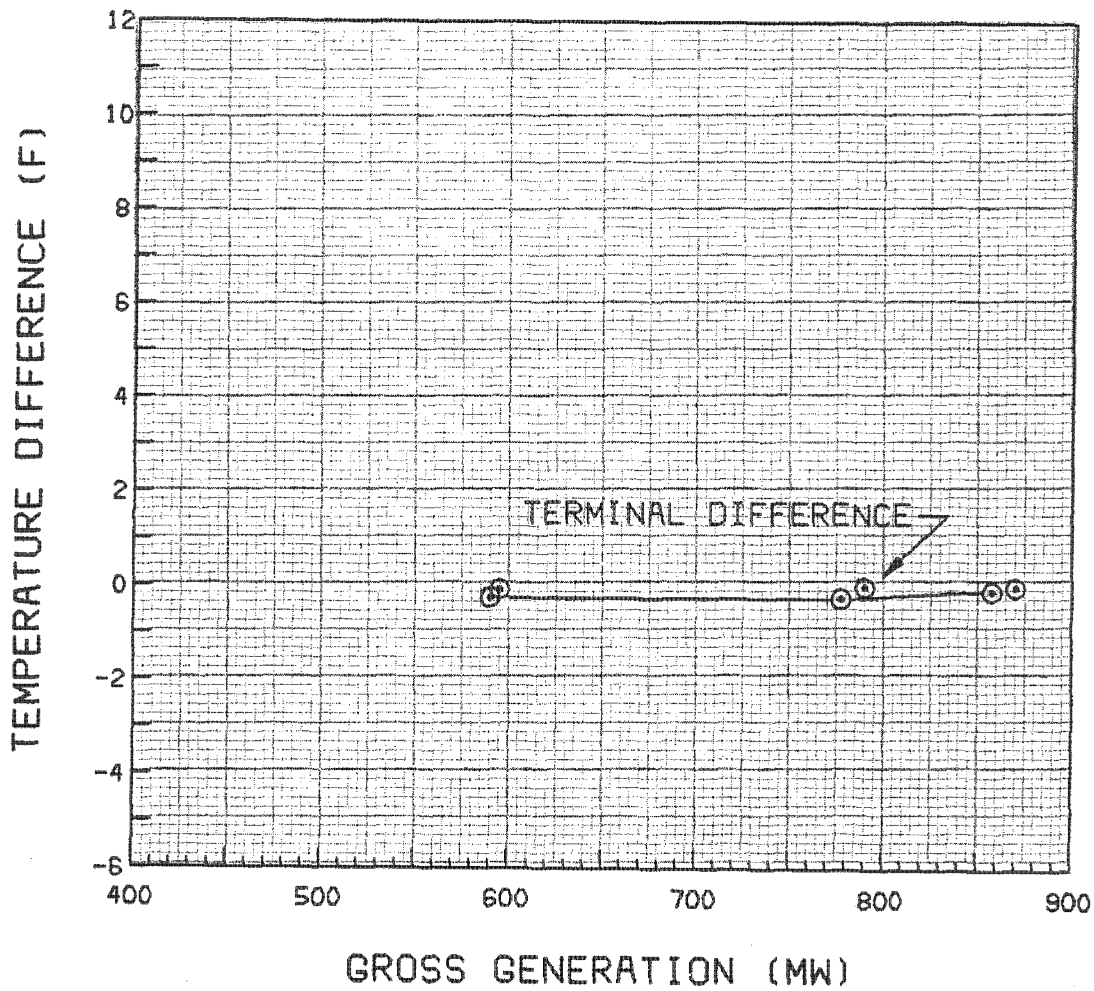


FIGURE 3-16: HEATER 5 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

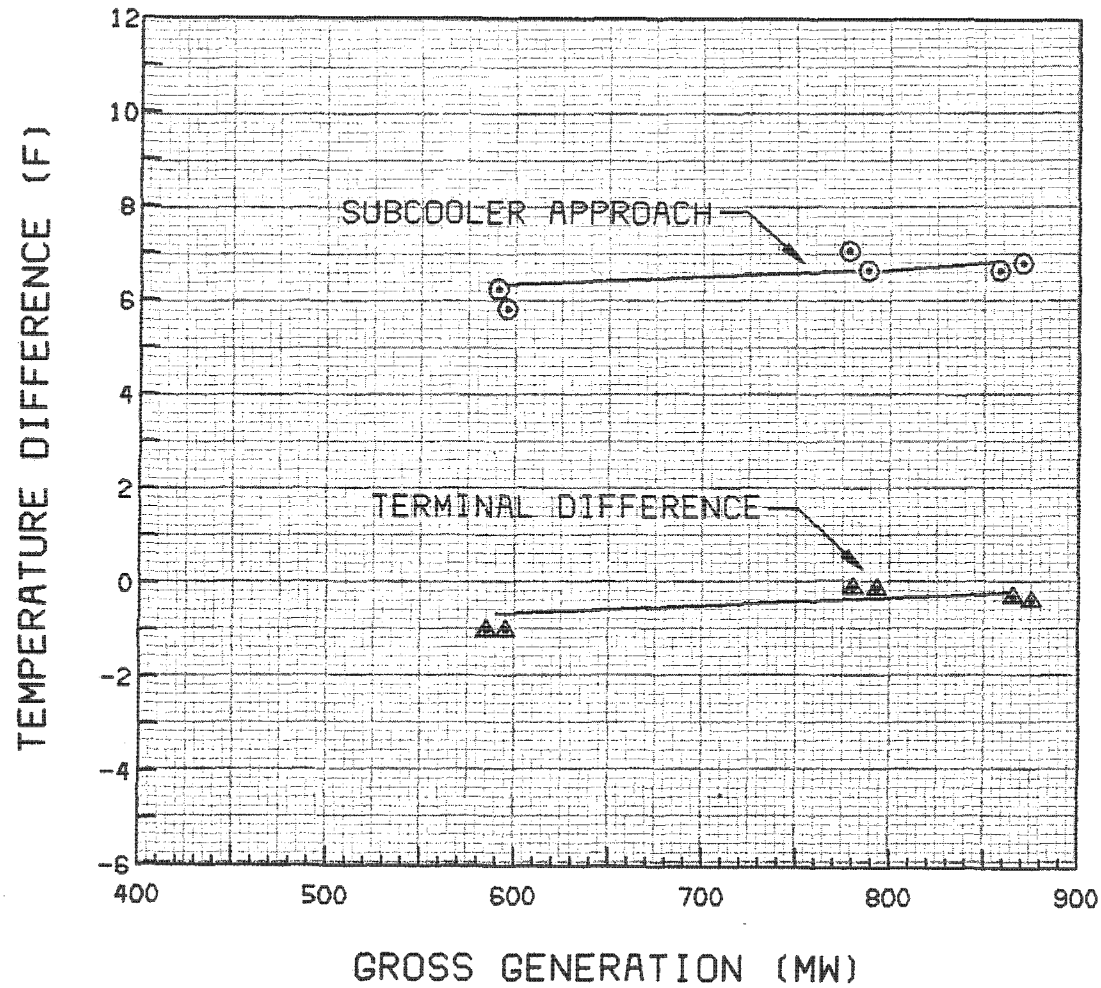


FIGURE 3-17: HEATER 4 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

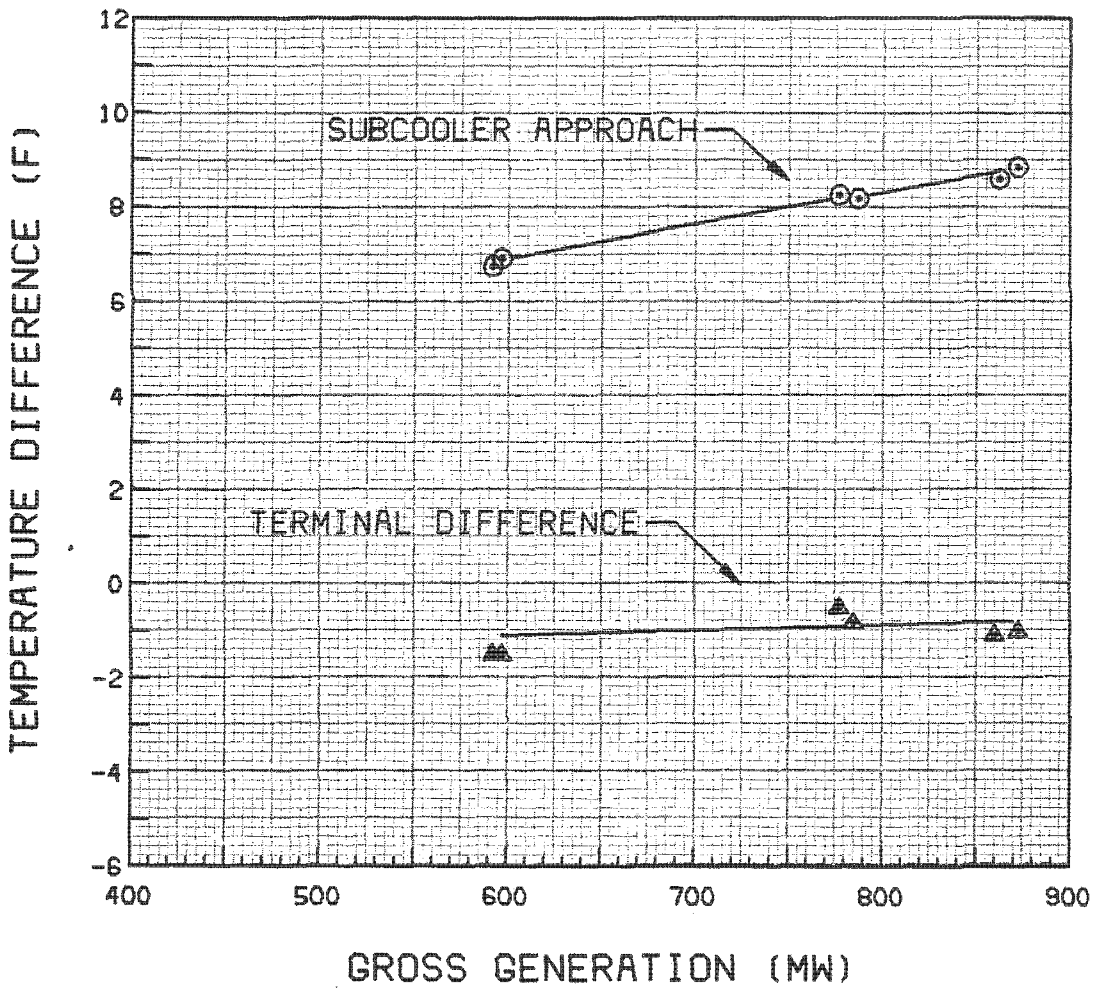


FIGURE 3-18: HEATER 3 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

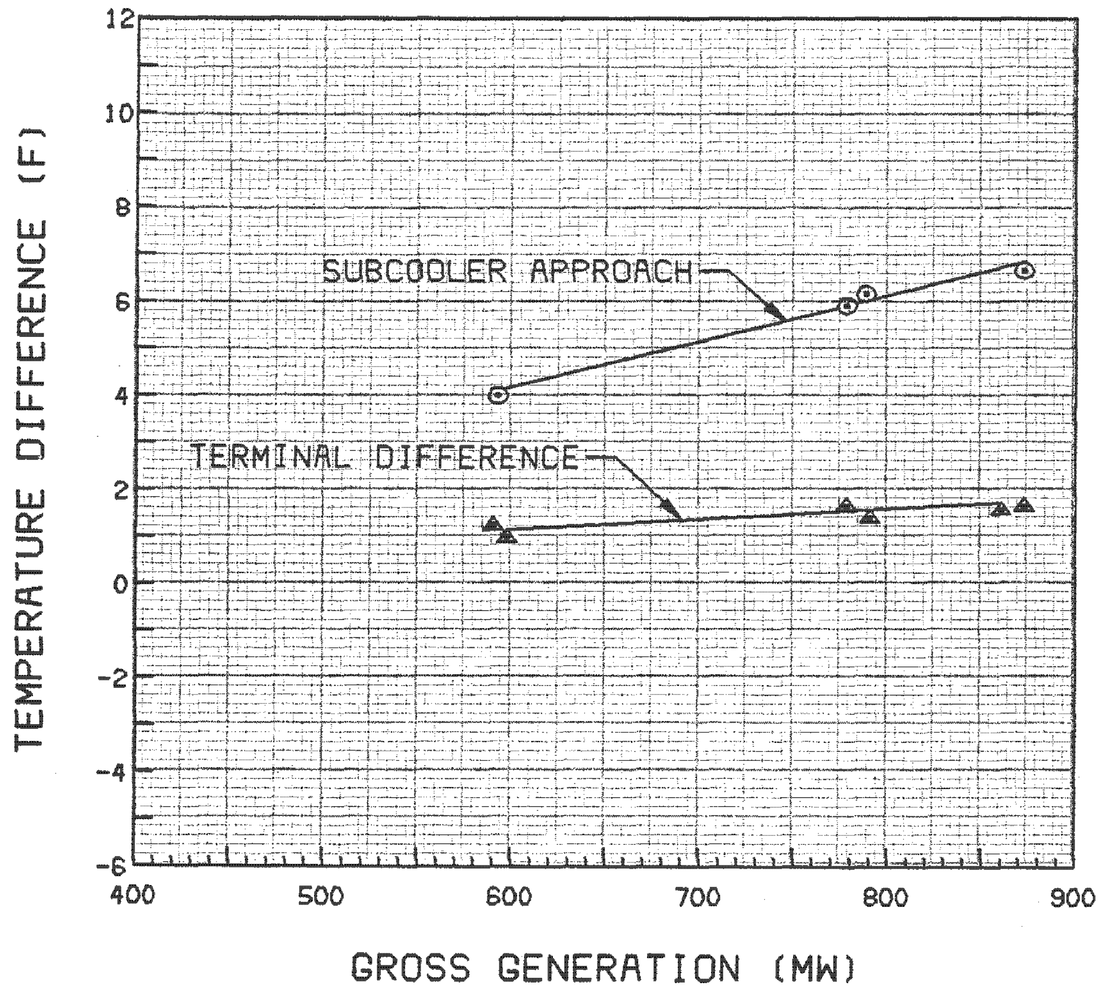


FIGURE 3-19: HEATER 2 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

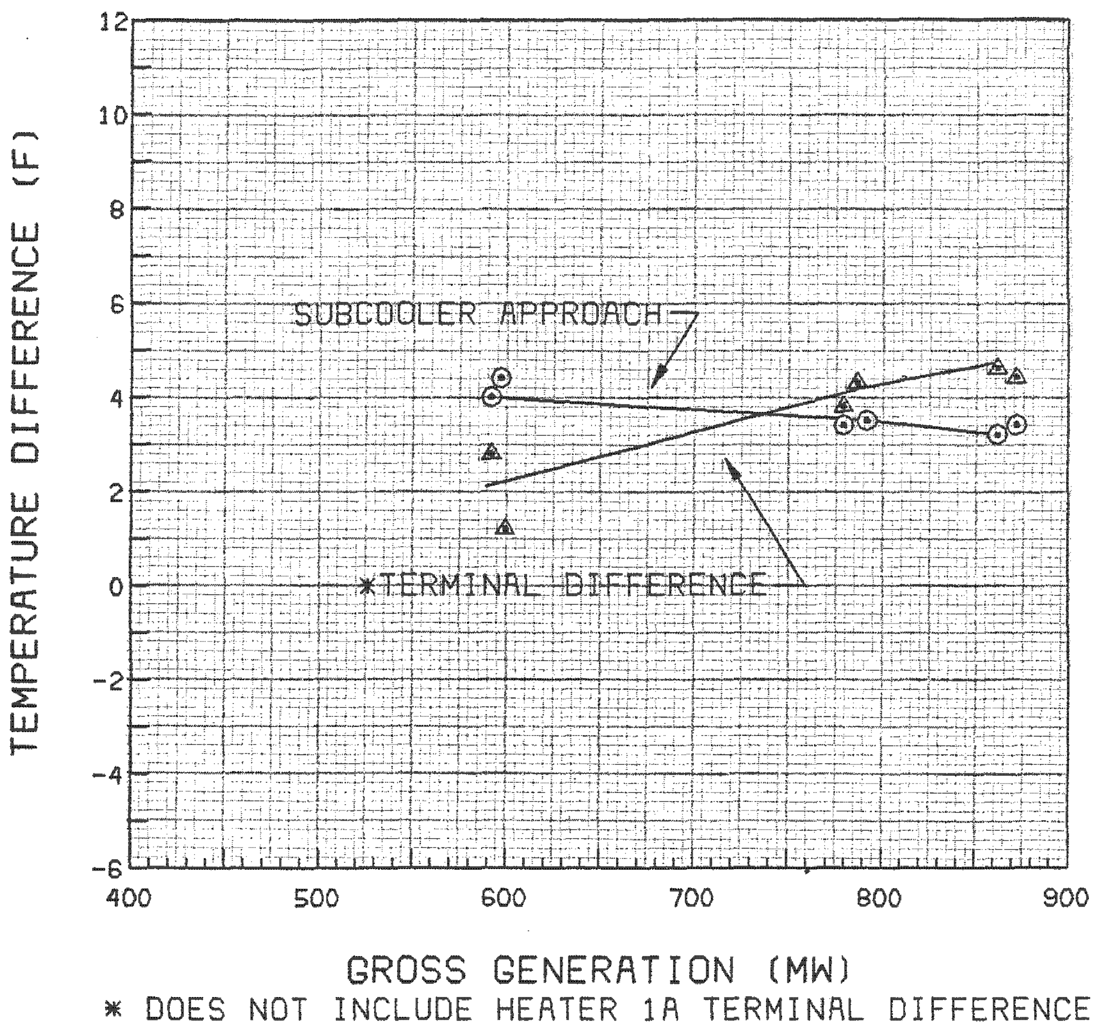


FIGURE 3-20: HEATER 1 PERFORMANCE
INTERMOUNTAIN POWER AGENCY
IPP UNIT 1

4.0 PROCEDURE

The performance test was conducted to determine net plant heat rate, and the performance and efficiencies of the major equipment in the cycle. Data collected also establishes bench mark data for the unit.

Preliminary tests were conducted to check operation and readings of all instruments directly related to the test. This also allowed determination of cycle leakages for isolation purposes.

Six tests; two each at valves wide open, third valve point, and second valve point, were conducted. Data was collected by General Electric test computer, the plant computer, and manually. Pressures, temperatures, important flow measurements and generator output were carefully measured with highly accurate measuring instruments. Balance-of-plant measurements were taken by plant instruments or by hand. All instruments were to be calibrated before testing commenced.

Generally, the tests began one hour after the unit had stabilized and were two hours in duration. Blowdown and makeup were isolated for the tests. Combustion conditions, rate of fuel flow, rate of feedwater flow, drum level, excess air, and all controllable temperatures and pressures were maintained as constant as possible for the duration of each test.

Data for each test was analyzed as soon as practicable after each test for acceptance. It was found in test six that a thermocouple ice point reference malfunctioned due to high ambient air temperature, causing thermocouples connected to it to read low. The affected temperature measurements were main steam, hot reheat, cold reheat, and feedwater heater number two drains. A method for acceptance of the test was devised to avoid the time and expense involved in conducting a third valves wide open test. The method for acceptance is as follows:

1. Extractions for Feedwater Heaters 7A and 7B are on the same line as cold reheat steam.
2. The difference in cold reheat and Feedwater Heater 7A and 7B extraction enthalpies should be the same for all tests at valves wide open.

3. The difference in enthalpies in test three were determined and applied to test six values. The resulting increase in cold reheat temperature was determined to be 3.8 F. This incremental temperature correction was then applied to the three remaining incorrect temperature readings. The corrected temperatures result in a higher heat rate.

The steam feedwater cycle was isolated as much as practicable to prevent large leakages. The condenser level was monitored to determine losses. Valves closed in the cycle for isolation are listed on the following pages.

VALVE ISOLATION LIST

MAIN STEAM SYSTEM
P&I DIAGRAM 1SGG-M2069

Class	Description	Valve Number
C	MAIN STEAM VENT TO ATMOSPHERE	1SGG-MBV-21
C	FILL LINE FOR SUPERHEATER HYDRO TEST	1SGG-BV-61
C	MAIN STEAM TO BFPT 1A	1SGG-MBV-9
C	MAIN STEAM TO BFPT 1B	1SGG-MBV-10
	USE TEMPERATURE MEASUREMENTS AT TW-13 AND TW-14 TO VERIFY ISOLATION.	
N	MAIN STEAM WARMING LINE	1SGG-MBV-17
N	MAIN STEAM WARMING LINE	1SGG-MCV-18
N	MAIN STEAM DRAIN TO BLOWDOWN TANK	1SGG-MBV-13
N	MAIN STEAM DRAIN TO BLOWDOWN TANK	1SGG-MBV-14
N	MAIN STEAM DRAIN TO CONDENSER	1SGG-MBV-25
N	MAIN STEAM DRAIN TO CONDENSER	1SGG-MBV-26
N	BFPT MAIN STEAM DRAIN TO BLOWDOWN TANK	1SGG-MBV-11
N	BFPT MAIN STEAM DRAIN TO BLOWDOWN TANK	1SGG-MBV-12
N	BFPT MAIN STEAM DRAIN TO CONDENSER	1SGG-MBV-55
N	BFPT MAIN STEAM DRAIN TO CONDENSER	1SGG-MBV-56
N	CONDENSATE TO DESUPERHEATER	1SGG-ACV-59
N	MAIN STEAM LINE WARMING DESUPERHEATER	1SGG-BV-58
N	MAIN STEAM LINE WARMING DESUPERHEATER	1SGG-MCV-18
N	SAMPLE NO. 14	1SGG-BV-16
N	CONDENSATE TO WARMING DESUPERHEATER	1SGG-BV-60

N - Non-critical
C - Critical

STEAM GENERATOR SYSTEM

P&I DIAGRAM 1SGA-M2063A

Class	Description	Valve Number
N	SUPERHEAT BYPASS TO CONDENSER Use tell tale valves 165/166 to verify isolation.	1SGA-BV-136
N	SUPERHEAT BYPASS TO CONDENSER	1SGA-BV-138
N	SUPERHEAT BYPASS TO CONDENSER Use tell tale valves 121/218 to verify isolation.	1SGA-BV-169
N	SUPERHEAT BYPASS TO CONDENSER	1SGA-BV-170
N	SUPERHEAT BYPASS TO REHEAT	1SGA-MBV-135
N	SUPERHEAT BYPASS TO REHEAT	1SGA-BV-125
N	SUPERHEAT BYPASS TO REHEAT	1SGA-ACV-134
N	SUPERHEAT BYPASS TO REHEAT	1SGA-MUV-133
N	BOILER SOOTBLOWING STEAM SUPPLY	1SGA-BV-141
C	BOILER SOOTBLOWING STEAM SUPPLY	1SGA-MBV-142
N	AH SOOTBLOWING STEAM SUPPLY	1SGA-BV-139
C	AH SOOTBLOWING STEAM SUPPLY	1SGA-MBV-140
N	BOILER SOOTBLOWING STEAM SUPPLY	1SGA-BV-143
C	BOILER SOOTBLOWING STEAM SUPPLY	1SGA-MBV-144
N	COMBUSTION GAS REHEATER SOOT BLOWING STEAM SUPPLY Use temperature indicator 1CCD-TI-120 to verify isolation.	1SGA-BV-17
N	COMBUSTION GAS REHEATER SOOT BLOWING STEAM SUPPLY	1SGA-MBV-24
N	STEAM SUPPLY TO AUX STEAM HEADER	1SGA-BV-10

STEAM GENERATOR SYSTEM (Continued)

P&ID DIAGRAM 1SGA-M2063A

Class	Description	Valve Number
N	STEAM SUPPLY TO AUX STEAM HEADER Use tell tale valves 203/204 to verify isolation.	1SGA-MBV-194
N	SECONDARY SUPERHEATER OUTLET HEADER	1SGI-BV-1
N	SECONDARY SUPERHEATER OUTLET HEADER	1SGI-BV-2
N	SECONDARY SUPERHEATER PLATEN OUTLET HEADER	1SGI-ACV-29
N	SECONDARY SUPERHEATER PLATEN OUTLET HEADER	1SGI-ACV-30

N - Non-critical

C - Critical

STEAM GENERATOR SYSTEM (Continued)

P&I DIAGRAM 1SGA-M2063B

Class	Description	Valve Number
N	GAGE GLASS LG-1 DRAIN	1SGA-BV-11
N	GAGE GLASS LG-1 DRAIN	1SGA-BV-12
N	GAGE GLASS LG-1 DRAIN	1SGA-BV-207
N	GAGE GLASS LG-3 DRAIN	1SGA-BV-25
N	GAGE GLASS LG-3 DRAIN	1SGA-BV-26
N	GAGE GLASS LG-2 DRAIN	1SGA-BV-18
N	GAGE GLASS LG-2 DRAIN	1SGA-BV-208
N	GAGE GLASS LG-2 DRAIN	1SGA-BV-19
N	FUTURE SAMPLE	1SGA-BV-54
N	DRAIN TO BLOWDOWN HEADER	1SGA-BV-31
N	DRAIN TO BLOWDOWN HEADER	1SGA-BV-32
C	CONTINUOUS BLOWDOWN	1SGA-MBV-4
C	CONTINUOUS BLOWDOWN	1SGA-BV-5
N	TO AUXILIARY STEAM SUPPLY	1SGA-BV-1
N	TO AUXILIARY STEAM SUPPLY	1SGA-MBV-2
	Use tell tale valves 206/205 to verify isolation.	
N	STEAM SUPPLY TO AUX STEAM HEADER TELL TALE	1SGA-BV-206
N	STEAM SUPPLY TO AUX STEAM HEADER TRAP	1SGA-BV-199
C	SAMPLE NO. 13	1SGA-BV-172

N - Non-critical

C - Critical

HOT/COLD REHEAT SYSTEM

P&I DIAGRAM 1SGJ-M2071

Class	Description	Valve Number
N	HOT REHEAT DRAINS	1SGJ-MBV-16
N	HOT REHEAT DRAINS	1SGJ-MBV-14
N	COLD REHEAT DRAINS	1SGJ-MBV-18
N	COLD REHEAT DRAINS	1SGJ-BV-56
N	COLD REHEAT DRAINS	1SGJ-BV-57
N	CNDS TO COLD REHEAT DRAIN DESUPERHEATER	1SGJ-ACV-89
N	CNDS TO HOT REHEAT DRAIN DESUPERHEATER	1SGJ-ACV-86
N	CNDS TO HOT REHEAT DRAIN DESUPERHEATER	1SGJ-ACV-87
C	REHEAT DESUPERHEATER	1SGJ-ABV-17

N - Non-critical

C - Critical

AUXILIARY STEAM SYSTEM

P&I DIAGRAM 1PSA-M2008

Class	Description	Valve Number
N	COLD REHEAT TO AUX STEAM Use tell tales valves 36/37 to verify isolation.	1PSA-MBV-17
N	COLD REHEAT TO AUX STEAM	1PSA-BV-15
N	COLD REHEAT TO AUX STEAM Use tell tale valves 123/127 to verify isolation.	1PSA-BV-12
N	COLD REHEAT TO AUX STEAM Use tell tale valves 123/127 to verify isolation.	1PSA-BV-14
N	AUX STEAM TO DEAERATOR	1PSA-BV-22
N	AUX STEAM TO DEAERATOR Use vent valve 118 to verify isolation.	1PSA-BV-21
N	AUX STEAM TO DEAERATOR STORAGE TANK Use tell tale valve 134 to verify isolation.	1PSA-BV-133
N	AUX STEAM TO DEAERATOR STORAGE TANK	1PSA-BV-6
N	AUX STEAM TO BFPT	1PSA-BV-19
N	AUX STEAM TO BFPT Use tell tale valves 39/40 to verify isolation.	1PSA-BV-18
N	AUX STEAM TO TURBINE SEALS	1PSA-BV-26
N	CNDS TO AUX STEAM DESUPERHEATER	1PSA-BV-7
N	CNDS TO AUX STEAM DESUPERHEATER	1PSA-BV-9
N	COLD REHEAT TO AUX STEAM TELL TALE	1PSA-BV-37

AUXILIARY STEAM SYSTEM (Continued)

P&I DIAGRAM 1PSA-M2008

Class	Description	Valve Number
N	MAIN DEAERATOR PREHEATING STEAM VENT	1PSA-BV-118
N	DEAERATOR STORAGE TANK CONDENSATE DEAERATION STEAM TELL TALE	1PSA-BV-134
N	BFPT STARTUP STEAM TELL TALE	1PSA-BV-40
N	COLD REHEAT TO AUX STEAM TELL TALE	1PSA-BV-36
N	STEAM FROM SECONDARY SUPERHEATER	1PSA-BV-58

N - Non-critical

C - Critical

BOILER VENTS AND DRAINS SYSTEM

P&I DIAGRAM 1SGF-M2068

DRAINS

Class	Description	Valve Number
N	LWR CONVEYOR PASS HEADER	1SGF-BV-28
N	LWR CONVEYOR PASS HEADER	1SGF-MBV-29
N	ECONOMIZER INLET HEADER	1SGF-BV-30
N	ECONOMIZER INLET HEADER	1SGF-BV-31
N	REHEATER INLET HEADER	1SGF-BV-33
N	REHEATER INLET HEADER	1SGF-BV-34
N	LWR CONVEYOR PASS HEADER	1SGF-BV-35
N	LWR CONVEYOR PASS HEADER	1SGF-MBV-36
N	REHEATER OUTLET HEADER	1SGF-BV-37
N	REHEATER OUTLET HEADER	1SGF-BV-38
N	REHEATER OUTLET HEADER	1SGF-BV-39
N	REHEATER OUTLET HEADER	1SGF-BV-40
N	SECONDARY SUPERHEATER OUTLET HEADER	1SGF-BV-41
N	SECONDARY SUPERHEATER OUTLET HEADER	1SGF-MBV-42
N	SECONDARY SUPERHEATER INTER INLET HEADER	1SGF-BV-43
N	SECONDARY SUPERHEATER INTER INLET HEADER	1SGF-MBV-44
N	SECONDARY SUPERHEATER INTER INLET HEADER	1SGF-BV-45
N	SECONDARY SUPERHEATER INTER INLET HEADER	1SGF-MBV-46
N	DRUM FEED HEADER	1SGF-BV-47
N	DRUM FEED HEADER	1SGF-BV-48
N	SECONDARY SUPERHEATER PLATEN INLET HEADER	1SGF-BV-49
N	SECONDARY SUPERHEATER PLATEN INLET HEADER	1SGF-MBV-50
N	ROOF INLET HEADER	1SGF-BV-51
N	ROOF INLET HEADER	1SGF-BV-52
N	DRUM FEED HEADER	1SGF-BV-53
N	DRUM FEED HEADER	1SGF-BV-54

BOILER VENTS AND DRAINS SYSTEM (Continued)

P&I DIAGRAM 1SGF-M2068

DRAINS

Class	Description	Valve Number
N	LWR CONVEYOR PASS HEADER	1SGF-BV-55
N	LWR CONVEYOR PASS HEADER	1SGF-MBV-56
N	LWR CONVEYOR PASS HEADER	1SGF-BV-57
N	LWR CONVEYOR PASS HEADER	1SGF-BV-58
N	DRUM WEST END	1SGF-BV-59
N	DRUM WEST END	1SGF-BV-60
N	DRUM WEST END	1SGF-BV-61
N	DRUM WEST END	1SGF-BV-62
N	DRUM WEST END	1SGF-BV-63
N	DRUM WEST END	1SGF-BV-64
N	DOWNCOMER DRAIN MANIFOLD	1SGF-BV-65
N	DOWNCOMER DRAIN MANIFOLD	1SGF-MBV-66
N	DRUM EAST END	1SGF-BV-67
N	DRUM EAST END	1SGF-BV-68
N	DRUM EAST END	1SGF-BV-69
N	DRUM EAST END	1SGF-BV-70

BOILER VENTS AND DRAINS SYSTEM (Continued)

VENTS

Class	Description	Valve Number
N	ECONOMIZER DISCHARGE LINE	1SGF-BV-17
N	PRIMARY SUPERHEATER OUTLET HEADER	1SGF-MBV-19
N	SECONDARY SUPERHEATER PLATEN OUTLET HEADER	1SGF-MBV-22
N	DRUM WEST END	1SGF-MBV-10
N	DRUM EAST END	1SGF-MBV-14
N	PRIMARY SUPERHEATER OUTLET HEADER	1SGF-MBV-24
N	ECONOMIZER DISCHARGE LINE	1SGF-BV-26

N - Non-critical

C - Critical

AUXILIARY STEAM SYSTEM

P&I DIAGRAM 9PSA-M2008

Class	Description	Valve Number
N	MAKEUP FROM UNIT 1 DEAERATOR	9PSA-BV-18
N	MAKEUP FROM UNIT 1 DEAERATOR	9PSA-BV-20
N	MAKEUP FROM UNIT 1 DEAERATOR	9PSA-BV-22
N	MAKEUP FROM UNIT 1 DEAERATOR	9PSA-BV-16
N	MAKEUP FROM UNIT 2 DEAERATOR TELL TALE	9PSA-BV-23

N - Non-critical

C - Critical

HIGH PRESS EXTRACTION SYSTEM

P&I DIAGRAM 1TEA-M2073

Class	Description	Valve Number
N	AUX STEAM TO BFPT	1TEA-MBV-118

N - Non-critical

C - Critical

EXTRACTION TRAPS AND DRAINS SYSTEM

P&I DIAGRAM 1TEA-M2075

Class	Description	Valve Number
C	HP HEATERS 8A AND 8B EXTR DRAIN	1TEC-BV-73
C	HP HEATERS 8A AND 8B EXTR DRAIN	1TEC-BV-75
C	HP HEATER 8A EXTR DRAIN	1TEC-BV-79
C	HP HEATER 8A EXTR DRAIN	1TEC-BV-81
C	HP HEATER 8B EXTR DRAIN	1TEC-BV-85
C	HP HEATER 8B EXTR DRAIN	1TEC-BV-87
C	HP HEATERS 6A AND 6B EXTR DRAIN	1TEC-BV-91
C	HP HEATERS 6A AND 6B EXTR DRAIN	1TEC-BV-93
C	HP HEATER 6A EXTR DRAIN	1TEC-BV-97
C	HP HEATER 6A EXTR DRAIN	1TEC-BV-99
C	HP HEATER 6B EXTR DRAIN	1TEC-BV-103
C	HP HEATER 6B EXTR DRAIN	1TEC-BV-105
C	BFPT 1B EXTR DRAIN	1TEC-BV-139
C	BFPT 1B EXTR DRAIN	1TEC-BV-141
C	BFPT 1A EXTR DRAIN	1TEC-BV-133
C	BFPT 1A EXTR DRAIN	1TEC-BV-135
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-127
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-129
C	BFPT 1A AND 1B EXTR DRAIN	1TEC-BV-121
C	BFPT 1A AND 1B EXTR DRAIN	1TEC-BV-123
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-115
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-117
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-109
C	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-BV-111
C	LP HEATER 3 EXTR DRAIN	1TEC-BV-33
N	LP HEATER 3 EXTR DRAIN	1TEC-BV-35

EXTRACTION TRAPS AND DRAINS SYSTEM (Continued)

P&I DIAGRAM 1TEA-M2075

Class	Description	Valve Number
C	LP HEATER 4 EXTR DRAIN	1TEC-BV-41
N	LP HEATER 4 EXTR DRAIN	1TEC-BV-43
C	LP HEATER 3 EXTR DRAIN	1TEC-BV-9
C	LP HEATER 3 EXTR DRAIN	1TEC-BV-11
C	LP HEATER 4 EXTR DRAIN	1TEC-BV-17
C	LP HEATER 4 EXTR DRAIN	1TEC-BV-19
C	LP HEATER 3 EXTR DRAIN	1TEC-BV-57
N	LP HEATER 3 EXTR DRAIN	1TEC-BV-59

N - Non-critical

C - Critical

EXTRACTION TRAPS AND DRAINS SYSTEM

P&I DIAGRAM 1TEC-M2075

Class	Description	Valve Number
C	LP HEATER 4 EXTR DRAIN	1TEC-BV-65
N	LP HEATER 4 EXTR DRAIN	1TEC-BV-67
C	BFPT 1A EXTR DRAIN	1TEC-BV-145
N	BFPT 1A EXTR DRAIN	1TEC-BV-147
C	BFPT 1B EXTR DRAIN	1TEC-BV-151
N	BFPT 1B EXTR DRAIN	1TEC-BV-153
N	MISCELLANEOUS DRAINS RCVR TANK Vent and overflow should be checked for leaks.	1TEC-BV-163
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-2
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-6
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-10
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-14
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-18
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-22
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-50
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-54
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-58
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-62
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-66
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-70
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-26
N	LP HEATER 2 EXTR DRAIN	1TEC-ACV-30
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-34
N	LP HEATER 3 EXTR DRAIN	1TEC-ACV-38
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-42
N	LP HEATER 4 EXTR DRAIN	1TEC-ACV-46

EXTRACTION TRAPS AND DRAINS (Continued)

P&I DIAGRAM 1TEC-M2075

Class	Description	Valve Number
N	HP HEATERS 8A AND 8B EXTR DRAIN	1TEC-ACV-74
N	HP HEATER 8A EXTR DRAIN	1TEC-ACV-80
N	HP HEATER 8B EXTR DRAIN	1TEC-ACV-86
N	HP HEATERS 6A AND 6B EXTR DRAIN	1TEC-ACV-92
N	HP HEATER 6A EXTR DRAIN	1TEC-ACV-98
N	HP HEATER 6B EXTR DRAIN	1TEC-ACV-104
N	BFPT 1B EXTR DRAIN	1TEC-ACV-140
N	BFPT 1A EXTR DRAIN	1TEC-ACV-134
N	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-ACV-128
N	BFPT 1A AND 1B EXTR DRAIN	1TEC-ACV-122
N	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-ACV-116
N	DEAERATOR HEATER 5 EXTR DRAIN	1TEC-ACV-110
N	BFPT 1A EXTR DRAIN	1TEC-ACV-146
N	BFPT 1B EXTR DRAIN	1TEC-ACV-152

NOTE: Isolation of the extraction drains should be verified by checking the surface temperature of the drain pipe.

N - Non-critical

C - Critical

CONDENSATE SYSTEM

P&I DIAGRAM 1FWC-M2037

Class	Description	Valve Number
N	FEEDWATER HEATER BYPASSES	1FWC-MBV-9
N	FEEDWATER HEATER BYPASSES	1FWC-MBV-16
N	FEEDWATER HEATER BYPASSES	1FWC-MBV-17
N	FEEDWATER HEATER BYPASSES	1FWC-MBV-18
N	DEAERATOR DRAIN TO CONDENSER Use tell tale valves 110 to verify isolation.	1FWC-BV-85
N	DEAERATOR DRAIN TO CONDENSER	1FWC-BV-86
C	DEAERATOR DRAIN TO CONDENSER Use tell tale valve 105 to verify isolation.	1FWC-BV-26
C	DEAERATOR DRAIN TO CONDENSER	1FWC-BV-27
N	DEAERATOR DRAIN TO GEN BLDG DRAIN	1FWC-BV-23
N	AIR PREHEAT SUPPLY	1FWC-BV-24
N	RECIRCULATION TO CONDENSER TELL TALE	1FWC-BV-110
N	RECIRCULATION TO CONDENSER DRAIN	1FWC-BV-105
N	DEAERATOR DRAIN	1FWC-BV-84
N	SAMPLE NO. 9	1FWC-BV-47

N - Non-critical

C - Critical

COMBUSTION GAS REHEAT SYSTEM

P&I DIAGRAM 1CCD-M2013A

Class	Description	Valve Number
N	DEAERATOR TO COMBUSTION GAS REHEAT Use tell tale valve to verify isolation.	1CCD-BV-150
N	DEAERATOR TO COMBUSTION GAS REHEAT	1CCD-BV-155
N	DEAERATOR TO COMBUSTION GAS REHEAT	1CCD-BV-156
N	DEAERATOR TO COMBUSTION GAS REHEAT	1CCD-BV-435
N	STEAM FROM SECONDARY SUPERHEATER PLATEN OUTLET HEADER	1CCD-BV-44
N	STEAM FROM SECONDARY SUPERHEATER PLATEN OUTLET HEADER	1CCD-BV-47
N	NORMAL RETURN TO CONDENSATE HEADER DOWNSTREAM OF HEATER 2 TELL TALE	1CCD-BV-436
N	ATTEMPERATOR SPRAY WATER FROM BFP DISCHARGE TELL TALE	1CCD-BV-246
N	COMBUSTION GAS REHEAT PUMPS RECIRCULATION	1CCD-BV-110
N	COMBUSTION GAS REHEAT PUMPS RECIRCULATION	1CCD-BV-113
N	COMBUSTION GAS REHEAT PUMPS RECIRCULATION	1CCD-BV-114
N	COMBUSTION GAS REHEAT PUMPS RECIRCULATION	1CCD-BV-117

NOTE: Use TE's 903, 904, and 905 to verify system isolation.

N - Non-critical

C - Critical

AIR PREHEAT SYSTEM

P&I DIAGRAM 1SGC-M2065

Class	Description	Valve Number
N	AIR PREHEAT PUMPS BYPASS	1SGC-BV-119
N	AIR PREHEAT PUMPS INLET	1SGC-BV-113
N	AIR PREHEAT PUMPS INLET	1SGC-BV-114
N	AIR PREHEAT RETURN TO CONDENSER	1SGC-BV-122
N	AIR PREHEAT RECIRCULATION	1SGC-BV-123
N	AIR PREHEAT RETURN CONTROL	1SGC-ACV-134
N	AIR PREHEAT RETURN TO DEAERATOR	1SGC-BV-140
N	AIR PREHEAT RETURN TO DEAERATOR TELL TALE	1SGC-BV-148
N	AIR PREHEAT PUMPS VENT	1SGC-BV-192
N	AIR PREHEAT PUMPS DRAIN	1SGC-BV-193
N	AIR PREHEAT PUMPS VENT	1SGC-BV-197
N	AIR PREHEAT PUMPS DRAIN	1SGC-BV-195
N	AIR PREHEAT RETURN TO CONDENSER	1SGC-BV-141
N	AIR PREHEAT RETURN TO CONDENSER TELL TALE	1SGC-BV-149
N	AIR PREHEAT EMERGENCY RETURN TO CONDENSER	1SGC-BV-137
N	AIR PREHEAT EMERGENCY RETURN TO CONDENSER	1SGC-BV-139
N	AIR PREHEAT EMERGENCY RETURN TO CONDENSER DRAIN	1SGC-BV-166
N	AIR PREHEAT EMERGENCY RETURN TO CONDENSER	1SGC-BV-130
N	AIR PREHEAT EMERGENCY RETURN TO CONDENSER	1SGC-BV-131

N - Non-critical

C - Critical

CONDENSING SYSTEM

P&I DIAGRAM 1HRA-M2020

Class	Description	Valve Number
C	CONDENSATE MAKEUP	1HRA-BV-30
C	CONDENSATE MAKEUP	1HRA-BV-31
N	CONDENSATE MAKEUP	1HRA-BV-33
N	CONDENSATE MAKEUP	1HRA-BV-34
C	CONDENSATE DRAWOFF	1HRA-BV-19
C	CONDENSATE DRAWOFF	1HRA-BV-20
N	CONDENSATE DRAWOFF	1HRA-BV-23
N	CONDENSATE DRAWOFF	1HRA-BV-24
N	CONDENSATE PUMP SEALS	1HRA-BV-71
	Use tell tale Valve 178 to verify isolation.	
N	CONDENSATE PUMP SEALS	1HRA-BV-179
N	CONDENSATE PUMP RECIRC	1HRA-ACV-25
N	CONDENSATE PUMP RECIRC	1HRA-BV-29
N	CONDENSATE NORMAL MAKEUP DRAIN	1HRA-BV-148
N	CONDENSATE EMERGENCY MAKEUP TELL TALE	1HRA-BV-175
N	CONDENSATE NORMAL DRAWOFF TELL TALE	1HRA-BV-176
N	CONDENSATE EMERGENCY DRAWOFF TELL TALE	1HRA-BV-177
N	CONDENSATE MISC SERVICE PUMPS	1HRA-BV-74
N	SAMPLE NO. 7	1HRA-BV-75
N	CONDENSATE MISC SERVICE PUMPS TELL TALE	1HRA-BV-178

N - Non-critical

C - Critical

CONDENSATE POLISHING SYSTEM

P&I DIAGRAM 1FWD-M2038A

Class	Description	Valve Number
	Do not regenerate polishers during test	
N	MAKEUP TO REGEN PUMPS	1FWD-BV-129

N - Non-critical

C - Critical

BOILER FEED SYSTEM

P&I DIAGRAM 1FWA-M2035A

Class	Description	Valve Number
C	BFP RECIRCULATION	1FWA-ACV-14
C	BFP RECIRCULATION	1FWA-ACV-15
C	BFP RECIRCULATION	1FWA-ACV-16
C	BFP RECIRCULATION	1FWA-ACV-17
C	BFP RECIRCULATION	1FWA-ACV-18
C	BFP RECIRCULATION	1FWA-ACV-19
N	BOOT STRAP STARTUP	1FWA-BV-298
	Use tell tale valve 108 to verify isolation.	
N	BOOT STRAP STARTUP	1FWA-BV-299
N	WARMUP DRAIN TO CONDENSER	1FWA-BV-188
	Use tell tale valve 365 to verify isolation.	
N	WARMUP DRAIN TO CONDENSER	1FWA-MBV-189
C	FEEDWATER HEATER BYPASS	1FWA-MBV-44
N	PHOSPHATE FEED	1FWA-BV-217
N	SAMPLE NO. 10	1FWA-BV-47
N	BOOT STRAP STARTUP LINE TELL TALE	1FWA-BV-108
N	WARMUP DRAIN TO CONDENSER TELL TALE	1FWA-BV-365

NOTE: All drains and vents to floor drains or atmosphere should be checked for leakage.

N - Non-critical

C - Critical

DRAINS AND VENTS

P&I DIAGRAM 1FWA-M2035C

Class	Description	Valve Number
N	BFPT DRAINS	1FWA-ABV-303
N	BFPT DRAINS	1FWA-ABV-304
N	BFPT DRAINS	1FWA-ABV-305
N	BFPT DRAINS	1FWA-ABV-306
N	BFPT DRAINS	1FWA-ABV-307
N	BFPT DRAINS	1FWA-ABV-308
N	BFPT DRAINS	1FWA-ABV-309
N	BFPT DRAINS	1FWA-ABV-310
N	BFPT DRAINS	1FWA-ABV-311
N	BFPT DRAINS	1FWA-ABV-312
N	BFPT DRAINS	1FWA-BV-389
N	BFPT DRAINS	1FWA-BV-391
C	BFPT DRAINS	1FWA-BV-393

N - Non-critical

C - Critical

HIGH PRESSURE HEATER DRAINS SYSTEM

P&I DIAGRAM 1TED-M2076

Class	Description	Valve Number
N	FEEDWATER TO CONDENSER	1TED-BV-270
N	FEEDWATER TO CONDENSER	1TED-BV-273
N	FEEDWATER TO CONDENSER	1TED-BV-269
N	FEEDWATER TO CONDENSER	1TED-BV-272
N	FEEDWATER TO CONDENSER	1TED-BV-268
N	FEEDWATER TO CONDENSER	1TED-BV-271

N - Non-critical

C - Critical

LOW PRESSURE HEATER DRAINS SYSTEM

P&I DIAGRAM 1TEE-M2077

Class	Description	Valve Number
N	LP HEATER 4 ALT DRAIN DRAIN	1TEE-BV-133
N	LP HEATER 3 ALT DRAIN DRAIN	1TEE-BV-139
N	LP HEATER 2 ALT DRAIN DRAIN	1TEE-BV-141
N	DRAIN COOLER TO CONDENSER DRAIN	1TEE-BV-142

N - Non-critical

C - Critical

TURBINE SEALS AND DRAINS SYSTEM

P&I DIAGRAM 1TGC-M2080A

Class	Description	Valve Number
C	MAIN STEAM SUPPLY	1TGC-BV-10*
N	MAIN STEAM SUPPLY	1TGC-MBV-3*
N	MAIN STEAM SUPPLY	1TGC-MBV-2*
N	MAIN STEAM SUPPLY	1TGC-ACV-1*
N	AUXILIARY STEAM SUPPLY	1TGC-MBV-6
N	AUXILIARY STEAM SUPPLY	1TGC-ACV-5
N	CONDENSATE TO STEAM SEAL DESUPERHEATER	1TGC-BV-25
N	AUXILIARY STEAM TO COLD REHEAT	1TGC-MBV-16
N	AUXILIARY STEAM TO COLD REHEAT	1TGC-BV-58
N	REHEAT VALVE DRAIN	1TGC-MBV-31
N	REHEAT VALVE DRAIN	1TGC-MBV-32
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-33
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-34
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-35
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-36
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-37
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-38
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-39
N	CONTROL VALVE/STOP VALVE DRAINS	1TGC-MBV-40
N	STEAM LEAD DRAIN	1TGC-MBV-49
N	HP TURB LEAKOFF TO STEAM SEALS	1TGC-ACV-17
N	AUX STEAM TO COLD REHEAT TELL TALE	1TGC-BV-57
N	AUX STEAM TO COLD REHEAT	1TGC-BV-58

* Requires full time operator. Must be opened quickly on a turbine trip.

N - Non-critical

C - Critical

TURBINE SYSTEM

P&I DIAGRAM 1TGA-M2079

Class	Description	Valve Number
N	VENTILATOR VALVE	1TGA-ABV-2

N - Non-critical

C - Critical

HEATER VENTS AND MISCELLANEOUS DRAINS SYSTEM

P&I DIAGRAMS 1TEF-M2078A AND M2078B

Relief valves, vents, and drains should be checked and isolated in accordance with previously discussed procedures.

5.0 SAMPLE CALCULATIONS

VARIABLE	DESCRIPTION	TEST 3 VALUE
TCND	TEMPERATURE OF CONDENSATE AT FLOW SECTION	298 F
PCND	PRESSURE OF CONDENSATE AT FLOW SECTION	137.7 PSIA
TAMB	TEMPERATURE OF AMBIENT AIR	98 F
G	LOCAL ACCELERATION OF GRAVITY	32.138 FT/SEC^2
TFWO8	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 8	556.2 F
PFWO8	PRESSURE OF FEEDWATER OUT OF FEEDWATER HEATER 8	2,792 PSIA
DPFWN	DIFFERENTIAL PRESSURE ACROSS FEEDWATER FLOW NOZZLE	61.208 PSID
DPCNDNA	DIFFERENTIAL PRESSURE ACROSS CONDENSATE FLOW NOZZLE TAP A	10.607 PSID
DPCNDNB	DIFFERENTIAL PRESSURE ACROSS CONDENSATE FLOW NOZZLE TAP B	10.627 PSID
TFGRR	TEMPERATURE OF FLUE GAS REHEAT RETURN WATER	226.5 F
PFGRR	PRESSURE OF FLUE GAS REHEAT RETURN WATER	207.2 PSIA
DPFGRR	DIFFERENTIAL PRESSURE ACROSS FLUE GAS REHEAT RETURN FLOW NOZZLE	1.262 PSID
TLO4	TEMPERATURE OF STEAM LEAKAGE NUMBER 4	781 F
PLO4	PRESSURE OF STEAM LEAKAGE NUMBER 4	125 PSIA
DPLO4	DIFFERENTIAL PRESSURE OF STEAM LEAKAGE NUMBER 4	6.923 PSID
TLO6	TEMPERATURE OF STEAM LEAKAGE NUMBER 6	605.5 F
PLO6	PRESSURE OF STEAM LEAKAGE NUMBER 6	125 PSIA
DPLO6	DIFFERENTIAL PRESSURE OF STEAM LEAKAGE NUMBER 6	2.942 PSID
TCLGLO	TEMPERATURE OF IP ROTOR COOLING STEAM	828 F
PCLGLO	PRESSURE OF IP ROTOR COOLING STEAM	531 PSIA

VARIABLE	DESCRIPTION	TEST 3 VALUE
DPCLGLO	DIFFERENTIAL PRESSURE OF IP ROTOR COOLING STEAM	9.225 PSID
TVSLO	TEMPERATURE OF VALVE STEM LEAKOFF STEAM	880 F
PVSLO	PRESSURE OF VALVE STEM LEAKOFF STEAM	538 PSIA
DPVSLO	DIFFERENTIAL PRESSURE OF VALVE STEM LEAK OFF STEAM	0.472 PSID
TLO2	TEMPERATURE OF STEAM LEAKAGE NUMBER 2	1,000 F
PLO2	PRESSURE OF STEAM LEAKAGE NUMBER 2	538 PSIA
PCLO2	PACKING CONSTANT OF STEAM LEAKAGE NUMBER 2	50
TLO5	TEMPERATURE OF STEAM LEAKAGE NUMBER 5	774 F
PLO5	PRESSURE OF STEAM LEAKAGE NUMBER 5	121.54 PSIA
PCLO5	PACKING CONSTANT OF STEAM LEAKAGE NUMBER 5	800
TLO7	TEMPERATURE OF STEAM LEAKAGE NUMBER 7	588 F
PLO7	PRESSURE OF STEAM LEAKAGE NUMBER 7	121.54 PSIA
PCLO7	PACKING CONSTANT OF STEAM LEAKAGE NUMBER 7	980
TLO8	TEMPERATURE OF STEAM LEAKAGE NUMBER 8	637 F
PLO8	PRESSURE OF STEAM LEAKAGE NUMBER 8	121.54 PSIA
PCLO8	PACKING CONSTANT OF STEAM LEAKAGE NUMBER 8	550
TLO9	TEMPERATURE OF STEAM LEAKAGE NUMBER 9	631 F
PLO9	PRESSURE OF STEAM LEAKAGE NUMBER 9	121.54 PSIA
PCLO9	PACKING CONSTANT OF STEAM LEAKAGE NUMBER 9	550
TDV1A	TEMPERATURE OF STEAM SEALS TO HEATER 1A	599 F
PDV1A	PRESSURE OF STEAM SEALS TO HEATER 1A	6.132 PSIA
DPDV1A	DIFFERENTIAL PRESSURE OF STEAM SEALS TO HEATER 1A	0.838 PSID
TDVCND	TEMPERATURE OF STEAM SEALS TO CONDENSER	682 F
PDVCND	PRESSURE OF STEAM SEALS TO CONDENSER	6.63 PSIA

VARIABLE	DESCRIPTION	TEST 3 VALUE
DPDVCND	DIFFERENTIAL PRESSURE OF STEAM SEALS TO CONDENSER	0.151 PSID
TEXTBFPTA	TEMPERATURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE A	619.6 F
PEXTBFPTA	PRESSURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE A	120.4 PSIA
DPEXTBFPTA1	DIFFERENTIAL PRESSURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE A	9.133 PSID
DPEXTBFPTA2	DIFFERENTIAL PRESSURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE A	9.310 PSID
TEXTBFPTB	TEMPERATURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE B	618.4 F
PEXTBFPTB	PRESSURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE B	120.9 PSIA
DPEXTBFPTB	DIFFERENTIAL PRESSURE OF EXTRACTION STEAM AT BOILER FEED PUMP TURBINE B	7.083 PSID
PBFPTTA	PRESSURE OF BOILER FEED PUMP TURBINE A THROTTLE STEAM	113.5 PSIA
SPBFPTA	SPEED OF BOILER FEED PUMP TURBINE A	5,456.3 RPM
HPBFPTA	HORSEPOWER OF BOILER FEED PUMP TURBINE A	15,045 HP
PBFPEXA	PRESSURE OF BFP TURBINE EXHAUST	2.075 PSIA
PFWPO	PRESSURE OF BOILER FEED PUMP DISCHARGE	2,929.6 PSIA
TFWPO	TEMPERATURE OF BOILER FEED PUMP DISCHARGE	346.5 F
PFWPI	PRESSURE OF BOILER FEED PUMP INLET	286.4 PSIA
TFWPI	TEMPERATURE OF BOILER FEED PUMP INLET	340.0 F
TCNDPD	TEMPERATURE OF CONDENSATE PUMP DISCHARGE	127.5 F
PCNDPD	PRESSURE OF CONDENSATE PUMP DISCHARGE	422.6 PSIA
PEXT8A	PRESSURE OF FEEDWATER HEATER 8A EXTRACTION STEAM	1,094.9 PSIA
TEXT8A	TEMPERATURE OF FEEDWATER HEATER 8A EXTRACTION STEAM	800.4 F

VARIABLE	DESCRIPTION	TEST 3 VALUE
PEXT8B	PRESSURE OF FEEDWATER HEATER 8B EXTRACTION STEAM	1,086.6 PSIA
TEXT8B	TEMPERATURE OF FEEDWATER HEATER 8B EXTRACTION STEAM	800.3 F
PEXT7A	PRESSURE OF FEEDWATER HEATER 7A EXTRACTION STEAM	574.3 PSIA
TEXT7A	TEMPERATURE OF FEEDWATER HEATER 7A EXTRACTION STEAM	626.9 F
PEXT7B	PRESSURE OF FEEDWATER HEATER 7B EXTRACTION STEAM	572.6 PSIA
TEXT7B	TEMPERATURE OF FEEDWATER HEATER 7B EXTRACTION STEAM	626.5 F
PEXT6A	PRESSURE OF FEEDWATER HEATER 6A EXTRACTION STEAM	233.4 PSIA
TEXT6A	TEMPERATURE OF FEEDWATER HEATER 6A EXTRACTION STEAM	799.1 F
PEXT6B	PRESSURE OF FEEDWATER HEATER 6B EXTRACTION STEAM	233.4 PSIA
TEXT6B	TEMPERATURE OF FEEDWATER HEATER 6B EXTRACTION STEAM	800.5 F
PEXT5	PRESSURE OF DEAERATING HEATER 5 EXTRACTION STEAM	121.3 PSIA
TEXT5	TEMPERATURE OF DEAERATING HEATER 5 EXTRACTION STEAM	619.9 F
PEXT4	PRESSURE OF FEEDWATER HEATER 4 EXTRACTION STEAM	64.83 PSIA
TEXT4	TEMPERATURE OF FEEDWATER HEATER 4 EXTRACTION STEAM	513.5 F
PEXT3	PRESSURE OF FEEDWATER HEATER 3 EXTRACTION STEAM	38.96 PSIA
TEXT3	TEMPERATURE OF FEEDWATER HEATER 3 EXTRACTION STEAM	412.8 F

VARIABLE	DESCRIPTION	TEST 3 VALUE
PEXT2	PRESSURE OF FEEDWATER HEATER 2 EXTRACTION STEAM	11.17 PSIA
TEXT2	TEMPERATURE OF FEEDWATER HEATER 2 EXTRACTION STEAM	230.5 F
PEXT1A	PRESSURE OF FEEDWATER HEATER 1A	5.537 PSIA
PEXT1B	PRESSURE OF FEEDWATER HEATER 1B	5.253 PSIA
PEXT1C	PRESSURE OF FEEDWATER HEATER 1C	5.175 PSIA
PFWECON	PRESSURE OF FEEDWATER AT ECONOMIZER	2,792 PSIA
PCND04	PRESSURE OF CONDENSATE OUT OF HEATER 4	177.1 PSIA
TDR8A	TEMPERATURE OF FEEDWATER HEATER 8A DRAINS	492.1 F
TDR8B	TEMPERATURE OF FEEDWATER HEATER 8B DRAINS	489.0 F
TDR7A	TEMPERATURE OF FEEDWATER HEATER 7A DRAINS	404.9 F
TDR7B	TEMPERATURE OF FEEDWATER HEATER 7B DRAINS	403.8 F
TDR6A	TEMPERATURE OF FEEDWATER HEATER 6A DRAINS	354.9 F
TDR6B	TEMPERATURE OF FEEDWATER HEATER 6B DRAINS	355.4 F
TDR4	TEMPERATURE OF FEEDWATER HEATER 4 DRAINS	273.1 F
TDR3	TEMPERATURE OF FEEDWATER HEATER 3 DRAINS	205.4 F
TDR2	TEMPERATURE OF FEEDWATER HEATER 2 DRAINS	163.2 F
TDR1	TEMPERATURE OF FEEDWATER HEATER 1 DRAINS	161.0 F
TFW08A	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 8A	556.3 F
TFW07A	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 7A	481.7 F
TFW06A	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 6A	397.1 F
TFW08B	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 8B	556.2 F
TFW07B	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 7B	481.2 F
TFW06B	TEMPERATURE OF FEEDWATER OUT OF FEEDWATER HEATER 6B	396.6 F

VARIABLE	DESCRIPTION	TEST 3 VALUE
TFW05	TEMPERATURE OF FEEDWATER OUT OF DEAERATING HEATER 5	342.1 F
TCND04	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 4	298.1 F
TCND03	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 3	266.6 F
TCND02	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 2	196.9 F
TCND01A	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 1A	145.8 F
TCND01B	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 1B	160.8 F
TCND01C	TEMPERATURE OF CONDENSATE OUT OF FEEDWATER HEATER 1C	160.4 F
TCNDI4	TEMPERATURE OF CONDENSATE INTO FEEDWATER HEATER 4	266.3 F
TCNDI3	TEMPERATURE OF CONDENSATE INTO FEEDWATER HEATER 3	196.9 F
TCNDI2	TEMPERATURE OF CONDENSATE INTO FEEDWATER HEATER 2	156.6 F
TCNDI1	TEMPERATURE OF CONDENSATE INTO FEEDWATER HEATER 1	134.3 F
TCNDIDC	TEMPERATURE OF CONDENSATE INTO DRAIN COOLER	129.4 F
PCNDI5	PRESSURE OF CONDENSATE INTO DEAERATOR	137.7 PSIA
PCNDDCI	PRESSURE OF CONDENSATE INTO DRAIN COOLER	227.3 PSIA
PEXTS4	PRESSURE OF STEAM AT STAGE 4 EXTRACTION	1,097.5 PSIA
TEXTS4	TEMPERATURE OF STEAM AT STAGE 4 EXTRACTION	801.7 F
PCRH	PRESSURE OF COLD REHEAT STEAM	583.4 PSIA
TCRH	TEMPERATURE OF COLD REHEAT STEAM	627.8 F

VARIABLE	DESCRIPTION	TEST 3 VALUE
PEXTS11	PRESSURE OF STEAM AT STAGE 11 EXTRACTION	236.5 PSIA
TEXTS11	TEMPERATURE OF STEAM AT STAGE 11 EXTRACTION	801.9 F
PEXTS14	PRESSURE OF STEAM AT STAGE 14 EXTRACTION	124.8 PSIA
TEXTS14	TEMPERATURE OF STEAM AT STAGE 14 EXTRACTION	618.9 F
PEXTS15	PRESSURE OF STEAM AT STAGE 15 EXTRACTION	66.4 PSIA
TEXTS15	TEMPERATURE OF STEAM AT STAGE 15 EXTRACTION	523.7 F
PEXTS16	PRESSURE OF STEAM AT STAGE 16 EXTRACTION	40.62 PSIA
TEXTS16	TEMPERATURE OF STEAM AT STAGE 16 EXTRACTION	420.0 F
PEXTS18	PRESSURE OF STEAM AT STAGE 18 EXTRACTION	11.87 PSIA
TEXTS18	TEMPERATURE OF STEAM AT STAGE 18 EXTRACTION	230.4 F
PEXTS19	PRESSURE OF STEAM AT STAGE 19 EXTRACTION	5.312 PSIA
PHDA	PRESSURE OF CONDENSER HOOD A	2.075 PSIA
PHDB	PRESSURE CONDENSER HOOD B	1.809 PSIA
PHDC	PRESSURE CONDENSER HOOD C	1.809 PSIA
FMSA	FLOW OF MAIN STEAM ATTEMPERATION	0 LB/HR
FBFPSIR	FLOW OF REJECTED SEAL INJECTION WATER FROM BOILER FEED PUMPS	70,627 LB/HR
TMS	TEMPERATURE OF MAIN STEAM	1,003.3 F
PMS	PRESSURE OF MAIN STEAM	2,421.4 PSIA
THRH	TEMPERATURE OF HOT REHEAT STEAM	1,000.5 F
PHRH	PRESSURE OF HOT REHEAT STEAM	538.1 PSIA
PHRHB	PRESSURE OF HOT REHEAT STEAM AT IP TURBINE BOWL	531.2 PSIA
PCXO	PRESSURE OF CROSSOVER STEAM	121.5 PSIA
TCXOB	TEMPERATURE OF CROSSOVER STEAM AT LP TURBINE BOWL	617.0 F

VARIABLE	DESCRIPTION	TEST 3 VALUE
PCXOB	PRESSURE OF CROSSOVER STEAM AT LP TURBINE BOWL	121.5 PSIA
PCNDS	PRESSURE OF CONDENSER, SPECIFIED	1.5 IN HG
QGEN	GENERATOR OUTPUT	871,725 KW
DPBFP1A	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOILER FEEDPUMP 1A	3.104 PSID
DPBFP1B	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOILER FEEDPUMP 1B	4.227 PSID
DPBFP1C	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOILER FEEDPUMP 1C	9.754 PSID
DPBFP2A	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOOSTER BOILER FEEDPUMP 2A	17.483 PSID
DPBFP2B	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOOSTER BOILER FEEDPUMP 2B	11.541 PSID
DPBFP2C	DIFFERENTIAL PRESSURE OF SEAL INJECTION WATER TO BOOSTER BOILER FEEDPUMP 2C	7.906 PSID
TCWOA	TEMPERATURE OF CIRCULATING WATER OUT OF HP CONDENSER A	120.4 F
TCWOB	TEMPERATURE OF CIRCULATING WATER OUT OF IP CONDENSER B	117.5 F
TCWOC	TEMPERATURE OF CIRCULATING WATER OUT OF LP CONDENSER C	105.3 F
TCWIA	TEMPERATURE OF CIRCULATING WATER INTO HP CONDENSER A	105.3 F
TCWIB	TEMPERATURE OF CIRCULATING WATER INTO IP CONDENSER B	91.2 F
TCWIC	TEMPERATURE OF CIRCULATING WATER INTO LP CONDENSER C	91.2 F

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
VSTD	SPECIFIC VOLUME WATER AT STANDARD CONDITIONS	0.01605 FT^3/LBM
VCND	SPECIFIC VOLUME OF CONDENSATE AT FLOW SECTION	0.01743 FT^3/LBM
VAMBC	SPECIFIC VOLUME OF CONDENSATE AT AMBIENT TEMPERATURE AT FLOW SECTION	0.01612 FT^3/LBM
VFW	SPECIFIC VOLUME OF FEEDWATER AT FEEDWATER FLOW NOZZLE	0.021344 FT^3/LBM
VAMBFW	SPECIFIC VOLUME OF FEEDWATER AT AMBIENT TEMPERATURE AT FEEDWATER FLOW NOZZLE	0.01600 FT^3/LBM
VFGR	SPECIFIC VOLUME OF FLUE GAS REHEAT AT FLOW NOZZLE	0.01680 FT^3/LBM
VAMBFGR	SPECIFIC VOLUME OF FLUE GAS REHEAT AT AMBIENT TEMPERATURE AT FLOW NOZZLE	0.01612 FT^3/LBM
VL04	SPECIFIC VOLUME OF LEAKOFF STEAM NUMBER 4	5.859 FT^3/LBM
VAMB4	SPECIFIC VOLUME OF WATER LEG LEAKOFF NUMBER 4 AT AMBIENT TEMPERATURE	0.01612 FT^3/LBM
VL06	SPECIFIC VOLUME OF LEAKOFF STEAM NUMBER 6	4.9889 FT^3/LBM
VAMB6	SPECIFIC VOLUME OF WATER LEG LEAKOFF NUMBER 6 AT AMBIENT TEMPERATURE	0.01612 FT^3/LBM
VCLGLO	SPECIFIC VOLUME OF IP ROTOR COOLING STEAM	1.3877 FT^3/LBM
VAMBCLG	SPECIFIC VOLUME OF WATER LEG IP ROTOR COOLING STEAM AT AMBIENT TEMPERATURE	0.01614 FT^3/LBM
VVSLO	SPECIFIC VOLUME OF VALVE STEM LEAKOFF	1.4323 FT^3/LBM
VAMBVS	SPECIFIC VOLUME OF WATER LEG STEM LEAKOFF AT AMBIENT TEMPERATURE	0.01610 FT^3/LBM
VL02	SPECIFIC VOLUME OF STEAM LEAKAGE NUMBER 2	1.5766 FT^3/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
VL05	SPECIFIC VOLUME OF STEAM LEAKAGE NUMBER 5	5.988 FT^3/LBM
VL07	SPECIFIC VOLUME OF STEAM LEAKAGE NUMBER 7	5.039 FT^3/LBM
VL08	SPECIFIC VOLUME OF STEAM LEAKAGE NUMBER 8	5.261 FT^3/LBM
VL09	SPECIFIC VOLUME OF STEAM LEAKAGE NUMBER 9	5.292 FT3/LBM
HL04	ENTHALPY OF STEAM LEAKAGE NUMBER 4	1,418.9 BTU/LBM
HL06	ENTHALPY OF STEAM LEAKAGE NUMBER 6	1,330.29 BTU/LBM
HL02	ENTHALPY OF STEAM LEAKAGE NUMBER 2	1,462.17 BTU/LBM
HL05	ENTHALPY OF STEAM LEAKAGE NUMBER 5	1,415.50 BTU/LBM
HL07	ENTHALPY OF STEAM LEAKAGE NUMBER 7	1,321.74 BTU/LBM
HL08	ENTHALPY OF STEAM LEAKAGE NUMBER 8	1,346.40 BTU/LBM
HL09	ENTHALPY OF STEAM LEAKAGE NUMBER 9	1,343.38 BTU/LBM
VDV1A	SPECIFIC VOLUME OF STEAM SEALS STEAM TO HEATER 1A	102.89 FT^3/LBM
VAMBDV1A	SPECIFIC VOLUME OF WATER LEG STEAM SEALS TO HEATER 1A	0.01613 FT^3/LBM
HDV1A	ENTHALPY OF STEAM SEALS TO HEATER 1A	1,335 BTU/LBM
VDVCND	SPECIFIC VOLUME OF STEAM SEALS TO CONDENSER	106.12 FT^3/LBM
VAMBVDC	SPECIFIC VOLUME OF WATER LEG STEAM SEALS TO CONDENSER AT AMBIENT TEMPERATURE	0.01613 FT^3/LBM
VEXTBFPTA	SPECIFIC VOLUME OF BOILER FEED PUMP TURBINE A EXTRACTION STEAM	5.2493 FT^3/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
VAMBEBFPTA	SPECIFIC VOLUME OF WATER LEG BOILER FEED PUMP TURBINE A EXTRACTION STEAM AT AMBIENT TEMPERATURE	0.01612 FT^3/LBM
VEXTBFPTB	SPECIFIC VOLUME OF BOILER FEED PUMP TURBINE B EXTRACTION STEAM	5.223 FT^3/LBM
VAMBEBFPTB	SPECIFIC VOLUME OF WATER LEG BOILER FEED PUMP TURBINE B EXTRACTION STEAM AT AMBIENT TEMPERATURE	0.01612 FT^3/LBM
HBFPTTA	ENTHALPY OF BOILER FEED PUMP TURBINE A THROTTLE STEAM	1,338.18 BTU/LBM
SBFPTTA	ENTROPY OF BOILER FEED PUMP TURBINE A THROTTLE STEAM	1.752797 BTU/LBM R
HBFPTESA	ENTHALPY OF BOILER FEED PUMP TURBINE A EXHAUST STEAM AT CONSTANT ENTROPY	1,020.42 BTU/LBM
VFWPDA	SPECIFIC VOLUME OF FEEDWATER AT BOILER FEED PUMP DISCHARGE	0.017709 FT^3/LBM
VFWPIA	SPECIFIC VOLUME OF FEEDWATER AT BOILER FEED PUMP INLET	0.01786 FT^3/LBM
VCNDPD	SPECIFIC VOLUME OF CONDENSATE AT CONDENSATE PUMP DISCHARGE	0.01622 FT^3/LBM
HEXT8A	ENTHALPY OF FEEDWATER HEATER 8A EXTRACTION STEAM	1,384.07 BTU/LBM
HEXT8B	ENTHALPY OF FEEDWATER HEATER 8B EXTRACTION STEAM	1,384.38 BTU/LBM
HEXT7A	ENTHALPY OF FEEDWATER HEATER 7A EXTRACTION STEAM	1,308.69 BTU/LBM
HEXT7B	ENTHALPY OF FEEDWATER HEATER 7B EXTRACTION STEAM	1,308.56 BTU/LBM
HEXT6A	ENTHALPY OF FEEDWATER HEATER 6A EXTRACTION STEAM	1,423.44 BTU/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
HEXT6B	ENTHALPY OF FEEDWATER HEATER 6B EXTRACTION STEAM	1,424.15 BTU/LBM
HEXT5	ENTHALPY OF FEEDWATER HEATER 5 EXTRACTION STEAM	1,337.81 BTU/LBM
HEXT4	ENTHALPY OF FEEDWATER HEATER 4 EXTRACTION STEAM	1,289.24 BTU/LBM
HEXT3	ENTHALPY OF FEEDWATER HEATER 3 EXTRACTION STEAM	1,242.78 BTU/LBM
HEXT2	ENTHALPY OF FEEDWATER HEATER 2 EXTRACTION STEAM	1,160.64 BTU/LBM
HEXT1	ENTHALPY OF FEEDWATER HEATER 1 EXTRACTION STEAM	1,090 BTU/LBM
TSEXT8A	TEMPERATURE OF FEEDWATER HEATER 8A SATURATED STEAM	555.70 F
TSEXT8B	TEMPERATURE OF FEEDWATER HEATER 8B SATURATED STEAM	554.75 F
TSEXT7A	TEMPERATURE OF FEEDWATER HEATER 7A SATURATED STEAM	481.52 F
TSEXT7B	TEMPERATURE OF FEEDWATER HEATER 7B SATURATED STEAM	481.21 F
TSEXT6A	TEMPERATURE OF FEEDWATER HEATER 6A SATURATED STEAM	394.97 F
TSEXT6B	TEMPERATURE OF FEEDWATER HEATER 6B SATURATED STEAM	394.97 F
TSEXT5	TEMPERATURE OF FEEDWATER HEATER 5 SATURATED STEAM	342.05 F
TSEXT4	TEMPERATURE OF FEEDWATER HEATER 4 SATURATED STEAM	297.80 F
TSEXT3	TEMPERATURE OF FEEDWATER HEATER 3 SATURATED STEAM	265.65 F

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
TSEXT2	TEMPERATURE OF FEEDWATER HEATER 2 SATURATED STEAM	198.47 F
TSEXT1A	TEMPERATURE OF FEEDWATER HEATER 1A SATURATED STEAM	166.59 F
TSEXT1B	TEMPERATURE OF FEEDWATER HEATER 1B SATURATED STEAM	164.29 F
TSEXT1C	TEMPERATURE OF FEEDWATER HEATER 1C SATURATED STEAM	163.66 F
HDR8A	ENTHALPY OF FEEDWATER HEATER 8A DRAINS	478.33 BTU/LBM
HDR8B	ENTHALPY OF FEEDWATER HEATER 8B DRAINS	485.21 BTU/LBM
HDR7A	ENTHALPY OF FEEDWATER HEATER 7A DRAINS	380.81 BTU/LBM
HDR7B	ENTHALPY OF FEEDWATER HEATER 7B DRAINS	379.61 BTU/LBM
HDR6A	ENTHALPY OF FEEDWATER HEATER 6A DRAINS	327.12 BTU/LBM
HDR6B	ENTHALPY OF FEEDWATER HEATER 6B DRAINS	327.66 BTU/LBM
HDR5	ENTHALPY OF FEEDWATER HEATER 5 DRAINS	313.50 BTU/LBM
HDR4	ENTHALPY OF FEEDWATER HEATER 4 DRAINS	242.16 BTU/LBM
HDR3	ENTHALPY OF FEEDWATER HEATER 3 DRAINS	173.61 BTU/LBM
HDR2	ENTHALPY OF FEEDWATER HEATER 2 DRAINS	131.20 BTU/LBM
HDR1	ENTHALPY OF FEEDWATER HEATER 1 DRAINS	128.93 BTU/LBM
HFW08A	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 8A	553.76 BTU/LBM
HFW08B	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 8B	553.69 BTU/LBM
HFW07A	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 7A	466.72 BTU/LBM
HFW07B	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 7B	466.11 BTU/LBM
HFW06A	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 6A	375.33 BTU/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
HFW06B	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 6B	374.75 BTU/LBM
HFWI6A	ENTHALPY OF FEEDWATER INTO FEEDWATER HEATER 6A	323.01 BTU/LBM
HFWI6B	ENTHALPY OF FEEDWATER INTO FEEDWATER HEATER 6B	323.19 BTU/LBM
HFW05	ENTHALPY OF FEEDWATER OUT OF FEEDWATER HEATER 5	313.5 BTU/LBM
HCND04	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 4	267.99 BTU/LBM
HCND03	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 3	235.75 BTU/LBM
HCND02	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 2	165.40 BTU/LBM
HCND01A	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 1A	114.22 BTU/LBM
HCND01B	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 1B	129.26 BTU/LBM
HCND01C	ENTHALPY OF CONDENSATE OUT OF FEEDWATER HEATER 1C	128.81 BTU/LBM
HCNDI5	ENTHALPY OF CONDENSATE INTO FEEDWATER HEATER 5	267.60 BTU/LBM
HCNDI4	ENTHALPY OF CONDENSATE INTO FEEDWATER HEATER 4	235.43 BTU/LBM
HCNDI3	ENTHALPY OF CONDENSATE INTO FEEDWATER HEATER 3	165.35 BTU/LBM
HCNDI2	ENTHALPY OF CONDENSATE INTO FEEDWATER HEATER 2	125.01 BTU/LBM
HCNDI1	ENTHALPY OF CONDENSATE INTO FEEDWATER HEATER 1	102.84 BTU/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
HEXTS4	ENTHALPY OF STAGE 4 EXTRACTION STEAM	1,388.24 BTU/LBM
HCRH	ENTHALPY OF COLD REHEAT STEAM	1,308.56 BTU/LBM
HEXTS11	ENTHALPY OF STAGE 11 EXTRACTION STEAM	1,424.75 BTU/LBM
HEXTS14	ENTHALPY OF STAGE 14 EXTRACTION STEAM	1,337.09 BTU/LBM
HEXTS15	ENTHALPY OF STAGE 15 EXTRACTION STEAM	1,294.10 BTU/LBM
HEXTS16	ENTHALPY OF STAGE 16 EXTRACTION STEAM	1,246.05 BTU/LBM
HEXTS18	ENTHALPY OF STAGE 18 EXTRACTION STEAM	1,160.38 BTU/LBM
HEXTS19	ENTHALPY OF STAGE 19 EXTRACTION STEAM	1,090 BTU/LBM
HCND	ENTHALPY OF CONDENSER HOTWELL SATURATED WATER	91.91 BTU/LBM
HMS	ENTHALPY OF MAIN STEAM	1,462.17 BTU/LBM
SMS	ENTROPY OF MAIN STEAM	1.53277 BTU/LBM R
HHPS	ENTHALPY OF HIGH PRESSURE TURBINE EXHAUST STEAM AT CONSTANT ENTROPY	1,287.36 BTU/LBM
HHRH	ENTHALPY OF HOT REHEAT STEAM	1,519.4 BTU/LBM
SHRH	ENTROPY OF HOT REHEAT STEAM	1.7285 BTU/LBM R
HCXO	ENTHALPY OF INTERMEDIATE PRESSURE TURBINE EXHAUST STEAM	1,336.38 BTU/LBM
HIPS	ENTHALPY OF INTERMEDIATE PRESSURE TURBINE EXHAUST STEAM AT CONSTANT ENTROPY	1,320.34 BTU/LBM

VARIABLES	DESCRIPTION	TEST 3 CALCULATED VALUE
SCXO	ENTROPY OF LOW PRESSURE TURBINE BOWL STEAM	1.743703 BTU/LBM R
HLPS	ENTHALPY OF LOW PRESSURE TURBINE EXHAUST STEAM AT CONSTANT ENTROPY	1,009.85 BTU/LBM
HCNDPD	ENTHALPY OF CONDENSATE AT CONDENSATE PUMP DISCHARGE	93.50 BTU/LBM
HBBFPD	ENTHALPY OF FEEDWATER AT BOOSTER BOILER FEED PUMP DISCHARGE	311.50 BTU/LBM
HHWA	ENTHALPY OF HP CONDENSER A HOTWELL	95.47 BTU/LBM
HHWB	ENTHALPY OF IP CONDENSER B HOTWELL	90.36 BTU/LBM
HHWC	ENTHALPY OF LP CONDENSER C HOTWELL	90.36 BTU/LBM
HAMB	ENTHALPY OF SATURATED WATER	172.0 BTU/LBM
HAMBCW	ENTHALPY OF CIRCULATING WATER AT AMBIENT TEMPERATURE AND PRESSURE	28.12 BTU/LBM

CALCULATION OF CONDENSATE FLOW

$$FCND = C \times K_M \times [(DPCND \times 33.9\ FT\ H_2O \times VCND)/(14.696\ PSIA \times VSTD)]^{0.5}$$

$$\times \frac{3600\ SEC}{1\ HR} \times \frac{1}{VCND} \times \frac{FT^3}{LBM}$$

$$K_M = \frac{A \times (2 \times G)^{0.5} \times F_A}{(1-B^4)^{0.5}}$$

A = NOZZLE THROAT AREA = 0.5283 FT^2

G = LOCAL ACCELERATION OF GRAVITY = 32.138 FT/SEC^2

F_A = NOZZLE TEMPERATURE EXPANSION FACTOR = 1.0042

B = RATIO OF THROAT DIAMETER TO PIPE DIAMETER = 0.4233

K_M = 4.323261

C = NOZZLE DISCHARGE COEFFICIENT =

FCND = 4,591,640 LBM/HR

CALCULATION OF FEEDWATER FLOW FROM NOZZLE PRESSURE DROP

$$FFW = C \times K_M \times [(DPFWN \times 33.9\ FT\ H_2O \times VFW)/(14.696\ PSIA \times VSTD)]^{0.5}$$

$$\times \frac{3600\ SEC}{1\ HR} \times \frac{1}{VFW}\ \frac{FT^3}{LBM}$$

A = 0.3323 FT^2

B = 0.4749

F_A = 1.0092

C = 0.9975

FFW = 6,362,270 LBM/HR

CALCULATION OF FLUE GAS REHEAT FLOW

$$FFGR = \frac{0.525\ IN}{FT^{1/2}\ SEC} \times D^2 \times C \times F_A \times (DPFGR \times VFGR)^{0.5} \times 3600 \times \frac{1}{VFGR}$$

D = DIAMETER OF ORIFICE = 7.2037 IN

C = 0.65

F_A = 1.0028

FFGR = 564,600 LBM/HR

CALCULATION OF STEAM LEAKAGE NUMBER 4 FLOW

$$FLO4 = 1890.07 \times D^2 \times K \times E \times Y \times [(DPLO4 \times VAMB4)/(VLO4 \times VSTD)]^{0.5}$$

D = ORIFICE DIAMETER = 3.216 IN

B = 0.799

K = NOZZLE DISCHARGE COEFFICIENT = 0.7765

E = NOZZLE EXPANSION FACTOR = 1 + 2 (9×10^{-6}) (TLO4-70F) = 1.0128

Y = EXPANSION FACTOR FOR COMPRESSIBLE FLOW =

$$1 - (0.41 + 0.35\ B^4)\ \frac{DPLO4}{PLO4 \times (1.3)} = 0.9765$$

FLO4 = 16,350 LBM/HR

CALCULATION OF STEAM LEAKAGE NUMBER 6 FLOW

$$FLO6 = 1890.07 \times D^2 \times K \times E \times Y \times [(DPLO6 \times VAMB6)/(VLO6 \times VSTD)]^{0.5}$$

D = 2.890 IN

B = 0.7178

K = 0.7047

E = 1.0096

Y = 0.9979

FLO6 = 8,630 LBM/HR

CALCULATION OF IP ROTOR COOLING STEAM FLOW

$$FCLGLO = 1890.07 \times D^2 \times K \times E \times Y \times [(DPCLGLO \times VAMBCLG)/(VCLGLO \times STD)]^{0.5}$$

D = 2.00 IN

B = 0.5227

K = 0.628

E = 1.0136

Y = 0.9942

FCLGLO = 12,370 LBM/HR

CALCULATION OF VALVE STEM LEAKOFF

$$FVSLO = 1890.07 \times D^2 \times K \times E \times Y \times [(DPVSLO \times VAMBVS)/(VVSLO \times VSTD)]^{0.5}$$

D = 1.818 IN

B = 0.7826

K = 0.770

E = 1.01458

Y = 0.99964

FVSLO = 2,800 LBM/HR

CALCULATION OF STEAM LEAKOFFS 2, 5, 7, 8, AND 9

$$FLO = (PLO/VLO)^{0.5} \times PC$$

FLO2 = 920 LBM/HR

FLO5 = 3,600 LBM/HR

FLO7 = 4,810 LBM/HR

FLO8 = 2,640 LBM/HR

FLO9 = 2,640 LBM/HR

CALCULATION OF STEAM SEALS FLOW TO HEATER 1A

$FDV1A = 1890.07 \times D^2 \times K \times [(DPDV1A \times VAMBDV1A)/(VDV1A \times VSTD)]^{0.5}$

D = 12.000 IN

K = 0.76

FDV1A = 18,710 LBM/HR

CALCULATION OF STEAM SEALS FLOW TO CONDENSER

$FDVCND = 1890.07 \times D^2 \times K \times [(DPDVCND \times VAMBDVC)/(VDVCND \times VSTD)]^{0.5}$

D = 10.020 IN

K = 0.76

FDVCND = 5,450 LBM/HR

CALCULATION OF BOILER FEED PUMP TURBINE STEAM FLOW

$$FSBFPT = 358.93 \times C \times Y \times F_A \times D^2 \times [(DPEXTBFPT \times 406.8\ IN\ H_20 \times VAMBEBFPT)/ (14.696\ PSIA \times VEXTBFPT \times VSTD)]^{0.5}/(1-B^4)$$

D = 7.809 IN

C_A = 0.997

F_A = 1.0105

Y = 0.957

B = 0.45269

FSBFPTA = 150,670 LBM/HR

C_A = 0.997

F_A = 1.0105

Y = 0.957

FSBFPTB = 132,360 LBM/HR

CALCULATION OF BOILER FEED PUMP SEAL INJECTION FLOWS

$$FBFPI = 0.0438 \times C \times D^2 \times F_A \times (DPBFPI \times 33.9 \text{ FT } H_2O/14.696 \text{ PSIA})^{0.5}$$

$$\times 3600 \frac{SEC}{HR} \times \frac{1}{VCNDPD}$$

F_A = 1.0011

D_1 = 0.9522 IN

B_1 = 0.49106

C_{1A} = 0.620

C_{1B} = 0.620

C_{1C} = 0.619

FBFP1AI = 14,640 LBM/HR

FBFP1BI = 17,080 LBM/HR

FBFP1CI = 25,910 LBM/HR

D_2 = 0.92515 IN

B_2 = 0.6168

C_{2A} = 0.655

C_{2B} = 0.655

C_{2C} = 0.655

FBFP2AI = 34,650 LBM/HR

FBFP2BI = 28,430 LBM/HR

FBFP2CI = 23,300 LBM/HR

FBFP1RJ = BOILER FEED PUMP REJECTED SEAL INJECTION FLOW = 19,292 LBM/HR

FBFP2RJ = BOOSTER FEED PUMP REJECTED SEAL INJECTION FLOW = 51,335 LBM/HR

FMSA = FLOW OF MAIN STEAM ATTEMPERATOR (STATION DATA) = 0 LBM/HR

FBFPSIR = BOILER FEED PUMP RETAINED SEAL INJECTION WATER

= FBFPI - (FBFP1RJ + FBFP2RJ)

= 73,380 LBM/HR

CALCULATION OF FEEDWATER HEATER 8 EXTRACTION FLOWS

(ASSUME HALF OF FEEDWATER FLOW THROUGH EACH FEEDWATER HEATER STRING AND NO HEAT LOSS FROM HEATERS)

$$FEXT8A = \frac{FFW}{2}\frac{(HFW08A - HFW07A)}{(HEXT8A - HDR8A)}$$

$$= 0.0480491 \ FFW$$

$$FEXT8B = \frac{FFW}{2}\frac{(HFW08B - HFW07B)}{(HEXT8B - HDR8B)}$$

$$= 0.0487005 \ FFW$$

CALCULATION OF FEEDWATER HEATER 7 EXTRACTION FLOWS

$$FEXT7A = \frac{FFW\ (0.5)(HFW07 - HFW06) + FEXT8A\ (HDR7A - HDR8A)}{(HEXT7A - HDR7A)}$$

$$= 0.0441967 \ FFW$$

$$FEXT7B = \frac{FFW\ (0.5)(HFW07 - HFW06) + FEXT8B\ (HDR7B - HDR8B)}{(HEXT7B - HDR7B)}$$

$$= 0.0436377 \ FFW$$

CALCULATION OF FEEDWATER HEATER 6 EXTRACTION FLOWS

$$FEXT6A = \frac{FFW\ (0.5)\ (HFW06A - HFWI6A) + (FEXT7A + FEXT8A)\ (HDR6A - HDR7A)}{(HEXT6A - HDR6A)}$$

$$= 0.0193441 \ FFW$$

$$FEXT6B = \frac{FFW\ (0.5)\ (HFW06B - HFWI6B) + (FEXT7B + FEXT8B)\ (HDR6B - HDR7B)}{(HEXT6B - HDR6B)}$$

$$= 0.0191365 \ FFW$$

CALCULATION OF DEAERATING HEATER 5 EXTRACTION FLOW

HEAT BALANCE AROUND HEATER 5

FEXT5 = [(FFW - FBFPSIR + FMSA)(HFW05) - FCND (HCNDI5) -
(FEXT8A + FEXT7A + FEXT6A)(HDR6A) - (FEXT8B + FEXT7B + FEXT6B)
(HDR6B) - FFGR (HFGRR - HFW05) - FL04 (HL04) - FL06 (HL06)]/HEXT5

FEXT5 = 0.1797497 FFW - 911,722 LBM/HR

MASS BALANCE AROUND HEATER 5

FEXT5 = FFW - FBFPSIR + FMSA - FCND - FL04 - FL06 - FEXT8A - FEXT7A -
FEXT6A - FEXT8B - FEXT7B - FEXT6B

FEXT5 = 0.7769354 FFW - 4,689,994 LBM/HR

SOLVING EQUATIONS SIMULTANEOUSLY

FFW = 6,326,800 LBM/HR

THUS SOLVING FOR HEATER EXTRACTION FLOWS

FEXT8A = 304,000 LBM/HR
FEXT8B = 308,120 LBM/HR
FEXT7A = 279,620 LBM/HR
FEXT7B = 276,090 LBM/HR
FEXT6A = 122,390 LBM/HR
FEXT6B = 121,070 LBM/HR
FEXT5 = 225,520 LBM/HR

CALCULATION OF FEEDWATER HEATER 4 EXTRACTION FLOW

$$FEXT4 = \frac{FCND\ (HCND04 - HCNDI4)}{(HEXT4 - HDR4)}$$

FEXT4 = 142,780 LBM/HR

CALCULATION OF FEEDWATER HEATER 3 EXTRACTION FLOW

$$FEXT3 = \frac{FCND\ (HCNDO3 - HCNDI3) + FEXT4\ (HDR3 - HDR4)}{(HEXT3 - HDR3)}$$

FEXT3 = 293,180 LBM/HR

CALCULATION OF FEEDWATER HEATER 2 EXTRACTION FLOW

$$FEXT2 = \frac{FCND\ (HCNDO2 - HCNDI2) + (FEXT3 + FEXT4)(HDR2 - HDR3)}{(HEXT2 - HDR2)}$$

FEXT2 = 162,190 LBM/HR

CALCULATION OF FEEDWATER HEATER 1 EXTRACTION FLOW

$$FEXT1A = \frac{FCND\ (0.3333)(HCNDO1A - HCNDI1) + FDV1A\ (HDR1 - HDV1A)}{(HEXT1A - HDR1)}$$

FEXT1A = 0 LBM/HR

$$FEXT1B = \frac{FCND\ (HCNDO1B - HCNDI1)}{3\ \ (HEXT1B - HDR1)}$$

FEXT1B = 42,080 LBM/HR

$$FEXT1C = \frac{FCND\ (HCNDO1C - HCNDI1)}{3\ \ (HEXT1C - HDR1)}$$

FEXT1C = 41,360 LBM/HR

Test turbine stage flows and condenser flows are then calculated by performing a mass balance around the turbine.

The used energy end point of the turbine is calculated by performing a heat balance around the turbine using the measured generator output and measured condenser flow.

The expansion line end point of the turbine is then iterated by assuming a steam quality at the test exhaust pressure and calculating the ELEP. This is done until the ELEP between successive iterations varies less than 0.1 BTU/LBM.

The turbine stage efficiencies are then calculated as follows:

$$\text{HPEFF} = \text{HIGH PRESSURE EFFICIENCY} = \frac{(\text{HMS} - \text{HCRH})}{(\text{HMS} - \text{HHPS})} \times 100\% = 87.96\%$$

$$\text{IPEFF} = \text{INTERMEDIATE PRESSURE EFFICIENCY} = \frac{(\text{HHRH} - \text{HCXO})}{(\text{HHRH} - \text{HIPS})} \times 100\% = 91.94\%$$

LPEFFE = LOW PRESSURE EXPANSION LINE END POINT EFFICIENCY

$$= \frac{(\text{HCXO} - \text{ELEP})}{(\text{HCXO} - \text{HLPS})} \times 100\% = 94.60\%$$

LPEFFU = LOW PRESSURE USED ENERGY END POINT EFFICIENCY

$$= \frac{(\text{HCXO} - \text{UEEP})}{(\text{HCXO} - \text{HLPS})} \times 100\% = 91.96\%$$

GROUP 1 CORRECTIONS

To accurately compare the test results from each load against the guarantee heat rate, it is necessary to correct the cycle from actual test conditions to specified conditions.

This is accomplished by calculating the test main steam flow and then assuming the following specified conditions.

1. No main or reheat steam attemperation.
2. No change in water level in the system or makeup.
3. No boiler feed pump seal injection.
4. Specified terminal difference and subcooler approach temperatures in the feedwater heaters.
5. Specified enthalpy rise across the condensate, boiler, and booster boiler feed pumps.
6. No subcooling of condensate leaving the condenser.
7. Specified pressure drops in feedwater heater extraction lines.
8. Seventy-five percent engine efficiency of boiler feed pump - boiler feed pump turbines.
9. No heat loss from extraction lines.
10. Specified flue gas reheat heat loss from deaerator.

Test flow/stage pressure ratios are calculated after each stage in the turbine with test temperatures and stage pressures. Then, new extraction flows are calculated using specified extraction line pressure drops, feedwater heater temperature differences and all other specified conditions as stated previously.

TEST RELATIONSHIP	W-LBM/H	P-PSIA	W/P
THROTTLE FLOW	6,326,800		
VALVE STEAM LEAKOFF	-3,730		
IP COOLING LEAKOFF	-12,370		
NO. 8 EXTRACTION FLOW	-612,120		
STEAM FLOW FOLLOWING EXTRACTION	5,698,580	1,097.5	5,192.3
NO. 4 GLAND LEAKOFF	-16,350		
NO. 5 GLAND LEAKOFF	-3,600		
NO. 6 GLAND LEAKOFF	-8,630		
NO. 7 GLAND LEAKOFF	-4,810		
NO. 7 EXTRACTION FLOW	-555,710		
REHEAT STEAM FLOW	5,109,480	538.1	9,495.4
VALVE STEAM LEAKOFF	+2,810		
IP COOLING LEAKOFF	+12,370		
NO. 6 EXTRACTION FLOW	-243,460		
STEAM FLOW FOLLOWING EXTRACTION	4,881,200	236.5	20,639.3
NO. 5 EXTRACTION FLOW	-225,520		
BFPT EXTRACTION FLOW	-283,030		
NO. 8 GLAND LEAKOFF	-2,640		
NO. 9 GLAND LEAKOFF	-2,640		

TEST RELATIONSHIP	W-LBM/H	P-PSIA	W/P
CROSSOVER STEAM FLOW	4,367,370	124.75	35,009.0
NO. 4 EXTRACTION FLOW	-142,780		
STEAM FLOW FOLLOWING EXTRACTION	4,224,590	66.6	64,432.3
NO. 3 EXTRACTION FLOW	-293,180		
STEAM FLOW FOLLOWING EXTRACTION	3,931,410	40.8	96,358.1
NO. 2 EXTRACTION FLOW	-162,190		
STEAM FLOW FOLLOWING EXTRACTION	3,769,220	11.97	314,889
NO. 1 EXTRACTION FLOW	-83,433		
STEAM FLOW TO CONDENSER	3,685,776	5.50	670,141

With the high pressure turbine exhaust pressure kept constant, new stage flows are calculated for the turbine and the flow at each stage is divided by the test flow/stage pressure ratio to find new extraction pressures. If these new extraction pressures vary by more than one percent from the previous extraction pressures, stage flows and stage extraction pressures are iterated until the difference in extraction pressures on all heaters between two successive iterations is less than one percent.

ITERATED STAGE FLOWS	FLOW, LBM/HR FIRST ITERATION	SECOND ITERATION
THROTTLE FLOW	6,326,800	6,326,800
VALVE STEM LEAKOFF	3,730	3,730
IP COOLING LEAKOFF	12,370	12,370
NO. 8 EXTRACTION FLOW	598,500	603,010
STEAM FLOW FOLLOWING EXTRACTION	5,712,196	5,707,690
NO. 4 GLAND LEAKOFF	16,350	16,350
NO. 5 GLAND LEAKOFF	3,600	3,600
NO. 6 GLAND LEAKOFF	8,630	8,630
NO. 7 GLAND LEAKOFF	4,810	4,810
NO. 7 EXTRACTION FLOW	574,430	573,810
REHEAT STEAM FLOW	5,104,370	5,100,480
VALVE STEAM LEAKOFF	2,810	2,810
IP COOLING LEAKOFF	12,370	12,370
NO. 6 EXTRACTION FLOW	233,130	241,860
STEAM FLOW FOLLOWING EXTRACTION	4,886,420	4,873,802
NO. 5 EXTRACTION FLOW	312,430	309,600
BFPT EXTRACTION FLOW	299,560	299,560
NO. 8 GLAND LEAKOFF	2,640	2,640
NO. 9 GLAND LEAKOFF	2,640	2,640
CROSSOVER STEAM FLOW	4,269,150	4,259,370
NO. 4 EXTRACTION FLOW	139,980	138,600
STEAM FLOW FOLLOWING EXTRACTION	4,129,170	4,120,770
NO. 3 EXTRACTION FLOW	282,680	279,590

ITERATED STAGE FLOWS	FLOW, LBM/HR FIRST ITERATION	SECOND ITERATION
STEAM FLOW FOLLOWING EXTRACTION	3,846,490	3,841,180
NO. 2 EXTRACTION FLOW	150,910	147,770
STEAM FLOW FOLLOWING EXTRACTION	3,695,580	3,693,410
NO. 1 EXTRACTION FLOW	119,910	119,300
STEAM FLOW TO CONDENSER	3,575,672	3,574,110

ITERATED STAGE PRESSURES, PSIA	TEST	FIRST ITERATION	SECOND ITERATION
STAGE 4	1,097.5	1,100.1	1,099.3
COLD REHEAT	583.4	583.4	583.4
HOT REHEAT	538.1	537.56	535.56
STAGE 11	236.5	236.75	236.14
STAGE 14	124.75	121.94	121.67
STAGE 15	66.60	65.10	64.96
STAGE 16	40.80	39.92	39.86
STAGE 18	11.97	11.74	11.73
STAGE 19	5.50	5.336	5.333

A new corrected generator load is calculated by performing a heat balance around the turbine using the new turbine flows. Electrical and mechanical losses in the generator are subtracted to find the corrected generator load.

The heat rate is then calculated using the new reheat flow and hot reheat enthalpy, condensate flow, and the specified enthalpy rise across the condensate and booster boiler feed pumps.

$$\text{HEAT RATE} = \frac{\text{QINPUT}}{\text{QGEN}}$$

QGEN = CORRECTED GENERATOR LOAD

QINPUT = FMS (HMS-HFW08) + FMS (DHBBFP)
+ FCND (DHCNDP) + FRHS (HHRH - HCRH)

DHCNDP = SPECIFIED ENTHALPY RISE ACROSS CONDENSATE PUMP

DHBBFP = SPECIFIED ENTHALPY RISE ACROSS BOOSTER BOILER FEED PUMP

TEST 3 GROUP I CORRECTED HEAT RATE = [6,326,796 (1,462.17 - 551.63) + 6,390,064 (1.45) + 4,636,815 (1.48) + 5,100,480 (1,522 - 1,308.6)]/866,708

TEST 3 HEAT RATE = 7,923 BTU/KW HR

Group II corrections are then applied to the heat rate and load for non-specified turbine steam conditions as follows:

		Heat Rate	Load
o Initial Throttle Pressure	-	1.0000	1.0040
o Initial Throttle Temperature	-	0.9997	1.0003
o Reheater Pressure Drop	-	0.9975	1.0070
o Exhaust Pressure	-	1.0260	0.9760
o Hot Reheat Steam Temperature	-	1.0000	1.0000

$$\text{CORRECTED HEAT RATE} = \frac{\text{HEAT RATE}}{\text{TOTAL GROUP II HEAT RATE CORRECTIONS}}$$

$$\text{CORRECTED LOAD} = \frac{\text{CORRECTED LOAD (GROUP I)}}{\text{TOTAL GROUP II LOAD CONNECTIONS}}$$

TOTAL GROUP II HEAT RATE CORRECTIONS = 1.023

TOTAL GROUP II LOAD CORRECTIONS = 0.987

CORRECTED HEAT RATE = 7,745 BTU/KW HR

CORRECTED LOAD = 878,124 KW

CALCULATION OF FEEDWATER HEATER PERFORMANCE

TD = TERMINAL TEMPERATURE DIFFERENCE

= TSAT - TFWI

TSAT = SATURATION TEMPERATURE OF EXTRACTION STEAM AT TEST PRESSURE

TFWO = TEMPERATURE OF FEEDWATER OUT OF HEATER

SA = SUBCOOLER APPROACH TEMPERATURE

= TDR - TFWI

TDR = FEEDWATER HEATER DRAIN TEMPERATURE

TFWI = TEMPERATURE OF FEEDWATER INTO HEATER

TD8A = -0.60 F

SA8A = 10.40 F

TD8B = -1.45 F

SA8B = 7.90 F

TD7A = -0.18 F

SA7A = 7.80 F

TD7B = 0.10 F

SA7B = 7.20 F

TD6A = -2.13 F

SA6A = 8.80 F

TD6B = -1.63 F

SA6B = 8.40 F

TD5 = -0.05 F

TD4 = -0.30 F

SA4 = 6.80 F

TD3 = -0.95 F

SA3 = 8.80 F

TD2 = +1.57 F

SA2 = 6.60 F

TD1A = 20.80 F

TD1B = 3.49 F

TD1C = 3.26 F

SA1 = 4.46 F

CALCULATION OF BOILER FEED PUMP TURBINE PERFORMANCE

BFPTSR = BOILER FEED PUMP TURBINE STEAM RATE

EFFBFPTA = EFFICIENCY OF BOILER FEED PUMP TURBINE A

UEEPBT = USED ENERGY END POINT OF BOILER FEED PUMP TURBINE

FBFPTAC = CORRECTED BOILER FEED PUMP TURBINE STEAM FLOW

F_1 = THROTTLE PRESSURE CORRECTION FACTOR

F_2 = THROTTLE TEMPERATURE CORRECTION FACTOR

F_3 = EXHAUST PRESSURE CORRECTION FACTOR

F_4 = TURBINE SPEED CORRECTION FACTOR

$$\text{EFFBFPTA} = \frac{\text{HBFPTTA} - \text{UEEPBT}}{\text{HBFPTTA} - \text{HBFPTESA}} \times 100\ \%$$

FBFPTAC = FBFPTA/(F_1 x F_2 x F_3 x F_4)

F_1 = 0.9974

F_2 = 1.0121

F_3 = 1.000

F_4 = 1.0038

FBFPTAC = 148,692 LBM/HR

UEEPBT = HBFPTTA - [HPBFPTA x 2,545 Btu/(FBFPTAC x 1 HP)]

EFFBFPTA = 81.04%

BFPTSR = FBFPTAC/HPBFPTA

BFPTSR = 9.88 LBM/HP HR

FFWBFPA = FLOW FEEDWATER BOILER FEED PUMP A (STATION DATA) = 3,256,000 LBM/HR

DH = DEVELOPED HEAD

VF = VOLUMETRIC FLOW

CVF = CORRECTED VOLUMETRIC FLOW

CDH = CORRECTED DEVELOPED HEAD

EDH = EXPECTED DEVELOPED HEAD

RP = RELATIVE PERFORMANCE

SG = SPECIFIC GRAVITY OF WATER PUMPED

EFFBFPA = BOILER FEED PUMP A EFFICIENCY

EFFBFPA = VF x DH x SG x 100 x 8.33/(33.000 x HPBFPTA)

VFWPA = AVERAGE SPECIFIC VOLUME WATER PUMPED

DH = [(VFWPDA x PFWPD) - (VFWPIA x PFWPI)] x 144 IN^2/FT^2

DH = 6,739 FT

VF = FFWBFPA x VFWPA x 7.4805/60

VF = 7,189 GPM

CVF = VF x 5,700 RPM/SPBFPTA

CVF = 7,576 GPM

CDH DH x $(5750)^2/SPBFPTA^2$

CDH = 7,484 FT

EDH = f(CVF)

= 8,123 FT

RP = DH/EDH

RP = 0.921

SG = 0.01605/VFWPA

SG = 0.906319

EFFBFPA = 73.67%

CONDENSER PERFORMANCE

FSCND = FLOW OF STEAM TO CONDENSER = 3,685,776 LBM/HR

TSATA = TEMPERATURE OF SATURATED WATER IN HP CONDENSER A = 127.5 F

TSATB = TEMPERATURE OF SATURATED WATER IN IP CONDENSER B = 122.4 F

TSATC = TEMPERATURE OF SATURATED WATER IN LP CONDENSER C = 122.4 F

CORRECTION FACTORS FOR OFF-DESIGN CIRCULATING WATER INLET TEMPERATURE - (SEE STANDARDS OF THE HEAT EXCHANGE INSTITUTE IN SECTION 6.0)

HTCFA = HEAT TRANSFER COEFFICIENT CORRECTION FOR HP CONDENSER A = 1.11

HTCFB = HEAT TRANSFER COEFFICIENT CORRECTION FOR IP CONDENSER B = 1.08

HTCFC = HEAT TRANSFER COEFFICIENT CORRECTION FOR LP CONDENSER C = 1.08

LOG MEAN TEMPERATURE DIFFERENCE

TLMDC = (TCWO - TCWI)/Ln[(TSAT - TCWI)/(TSAT - TCWO)]

TLMDCA = 13.22 F

TLMDCB = 14.18 F

TLMDCC = 23.40 F

TERMINAL TEMPERATURE DIFFERENCE

TTD = TSAT - TCWO

TTDA = 7.1 F

TTDB = 4.9 F

TTDC = 17.1 F

FCNDC = FLOW TO CONDENSER C = FSCND/3 + FSBFPTB + FEXT4 + FEXT3 + FEXT2 + FEXT1A + FEXT1B + FEXT1C + FDV1A

FCNDC = 2,061,250 LBM/HR

FCNDB = FLOW TO CONDENSER B = FSCND/3 + FCNDC

FCNDB = 3,289,842 LBM/HR

FCNDA = FLOW TO CONDENSER A = FSCND/3 + FCNDB + FSBFPTA + FDVCND

FCNDA = 4,676,764 LBM/HR

INDIVIDUAL USED ENERGY END POINT OF EACH CONDENSER

UEEPA = 1,042.0 BTU/LBM

UEEPB = 1,033.1 BTU/LBM

UEEPC = 1,033.1 BTU/LBM

QCND= HEAT TRANSFERRED TO CIRCULATING WATER IN CONDENSER

QCNDA = 1,299,209,627 BTU/HR

QCNDB = 1,158,279,680 BTU/HR

QCNDC = 1,296,695,508 BTU/HR

CALCULATED HEAT TRANSFER COEFFICIENT

UC = QCND/(AREA OF CONDENSER x TLMDC)

AREA = 150,000 FT^2

UCA = 655.2 BTU/HR - FT^2 - F

UCB = 544.6 BTU/HR - FT^2 - F

UCC = 369.4 BTU/HR - FT^2 - F

CORRECTED HEAT TRANSFER COEFFICIENT

UCXC = UC X TCFCW

UCAC = 727.2 BTU/HR - FT^2 - F

UCBC = 588.1 BTU/HR - FT^2 - F

UCCC = 399.0 BTU/HR - FT^2 - F

CLEANLINESS FACTOR

CFC = 100 x UCXC/UDCX

UDCX = MINIMUM CLEANLINESS HEAT TRANSFER COEFFICIENT

CFCA = 727.2 x 100/603.13 = 120.6 PERCENT

CFCB = 588.1 x 100/604.26 = 97.3 PERCENT

CFCC = 399.0 x 100/604.26 = 66.0 PERCENT

6.0 REFERENCES

"Fluid Meters"; American Society of Mechanical Engineers - Sixth Edition, New York, 1971.

"Flow of Fluids"; Crane Engineering Division, Technical Paper No. 410, New York, 1985.

"ASME Steam Tables"; American Society of Mechanical Engineers - Fourth Edition, New York, 1979.

"Steam Turbines, PTC 6.0"; American Society of Mechanical Engineers, New York, 1976.

"Steam Turbines, PTC 6.0, Appendix A"; American Society of Mechanical Engineers, New York, 1982.

"Steam Turbines, PTC 6.1, Alternative Test"; American Society of Mechanical Engineers, New York, 1984.

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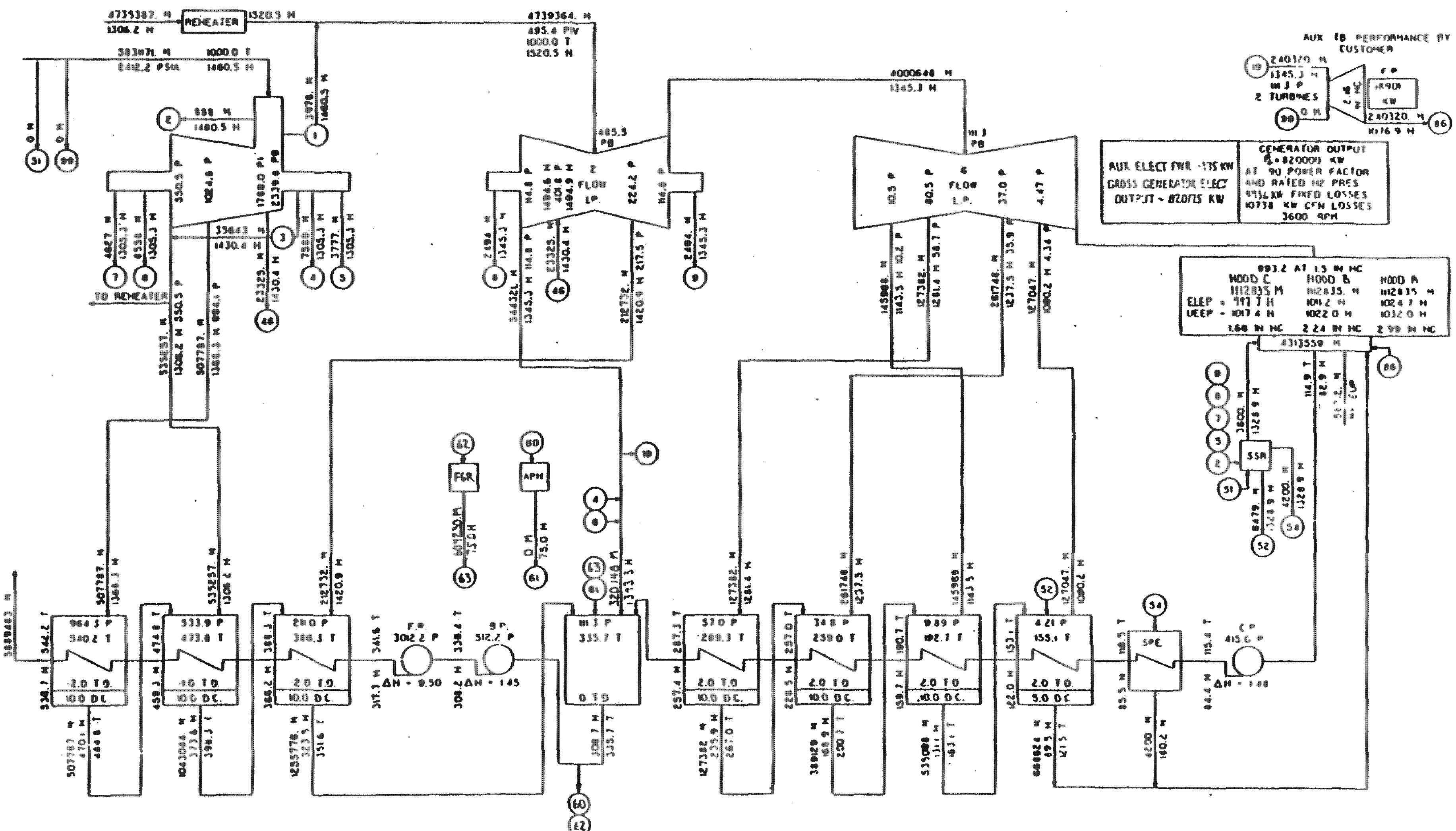
EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY



CUSTOMER DEFINED
VALVE BEST POINT = $\frac{5831171.M(1460.5H-536.7H)+4735387.M(1520.5H-1306.2H)+4313559.M(1.48H)+5831.M(720.5H-536.7H)}{820000\ KW} = 7816\ \frac{Btu}{Kw\text{-}Hr}$
NET HEAT RATE

LEGEND CALCULATIONS BASED
ON 1967 ASME STEAM TABLES
W - FLOW LB/HR
P - PRESSURE-PSIA
H - ENTHALPY BTU/LB
T - TEMPERATURE-F DEGREES

820000 KW 166 / 2.24 / 2.99 IN HC AB, 100 PCT MU
TC6F 30.0 IN LSP 3600 RPM
2400 PSIG 1000 / 1000 F
GEN 991000 KVA 90 PF LIQ

Klw Koran

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GENERAL ELECTRIC COMPANY SCHENECTADY N.Y.

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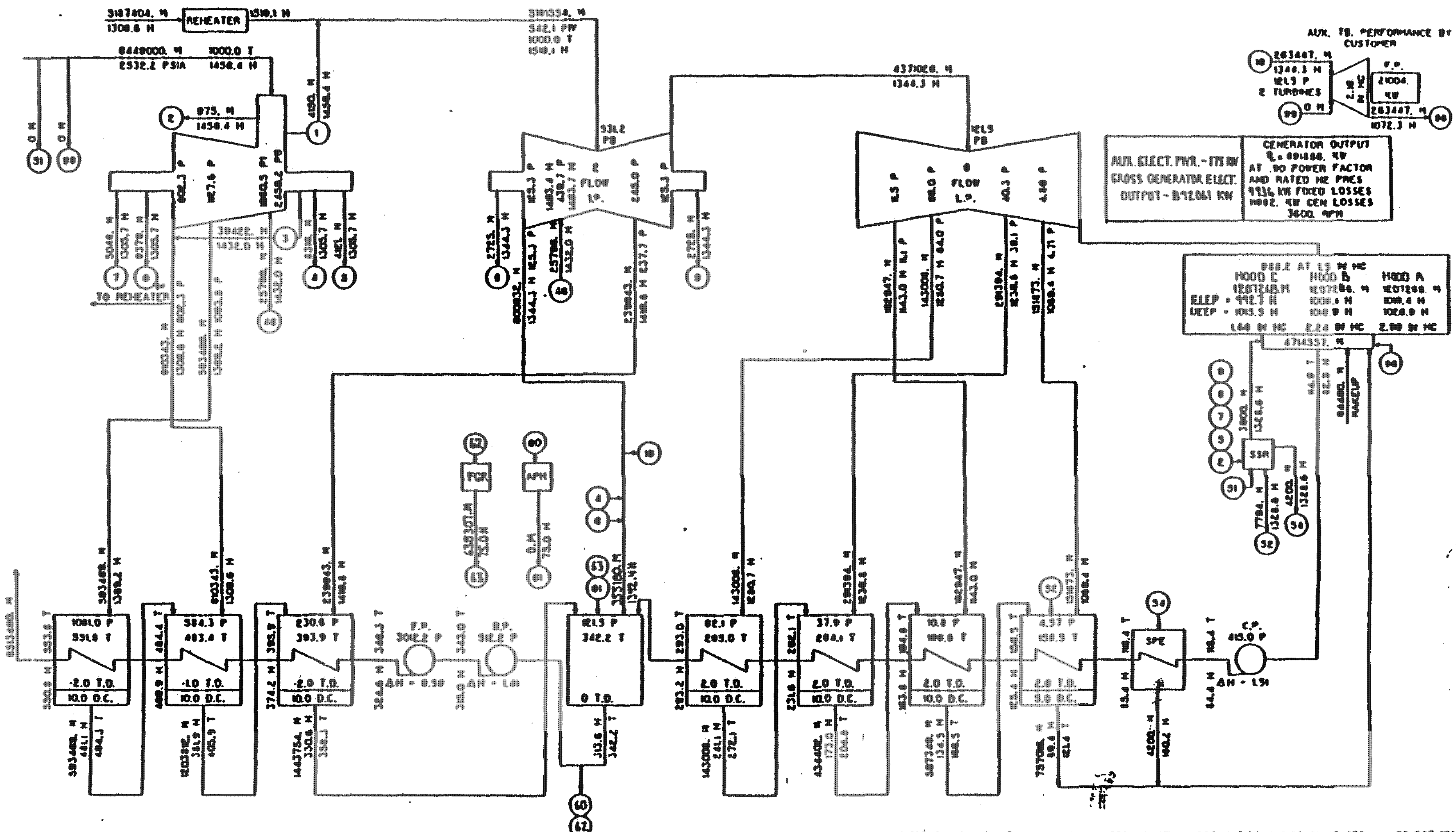
481 HB HE

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

CALCULATED DATA · NOT GUARANTEED

RATING FLOW IS 583H7L M AT INLET STEAM CONDITIONS OF 2412.2 PSIA AND 1000.0 T
TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS
FROM EXPECTED VALUES, SHOP TOLERANCES ON DRAWING AREAS, ETC. WHICH MAY AFFECT THE FLOW, THE
TURBINE IS BEING DESIGNED FOR A DESIGN FLOW RATING FLOW PLUS 5.0 PERCENT OF 6122730. M
THE EQUIVALENT DESIGN FLOW AT 2532.2 PSIA AND 1000.0 T IS 6449000. M .



CUSTOMER DEFINED
VALVE BEST POINT = $\frac{6449000.M(1456.4H-550.0H)+5187404.M(1519.1H-1306.6H)+4714557.M(1.51H)+6449.M(720.5H-550.0H)}{891886\ KW}$ = 7793 $\frac{Btu}{Kw\text{-}Hr}$
NET HEAT RATE

LEGEND CALCULATIONS BASED
ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T TEMPERATURE-F DEGREES

820000. KW 1.68 / 2.24 / 2.90 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. F
GEN- 991000. KVA .90 PF L18

Klw Koran

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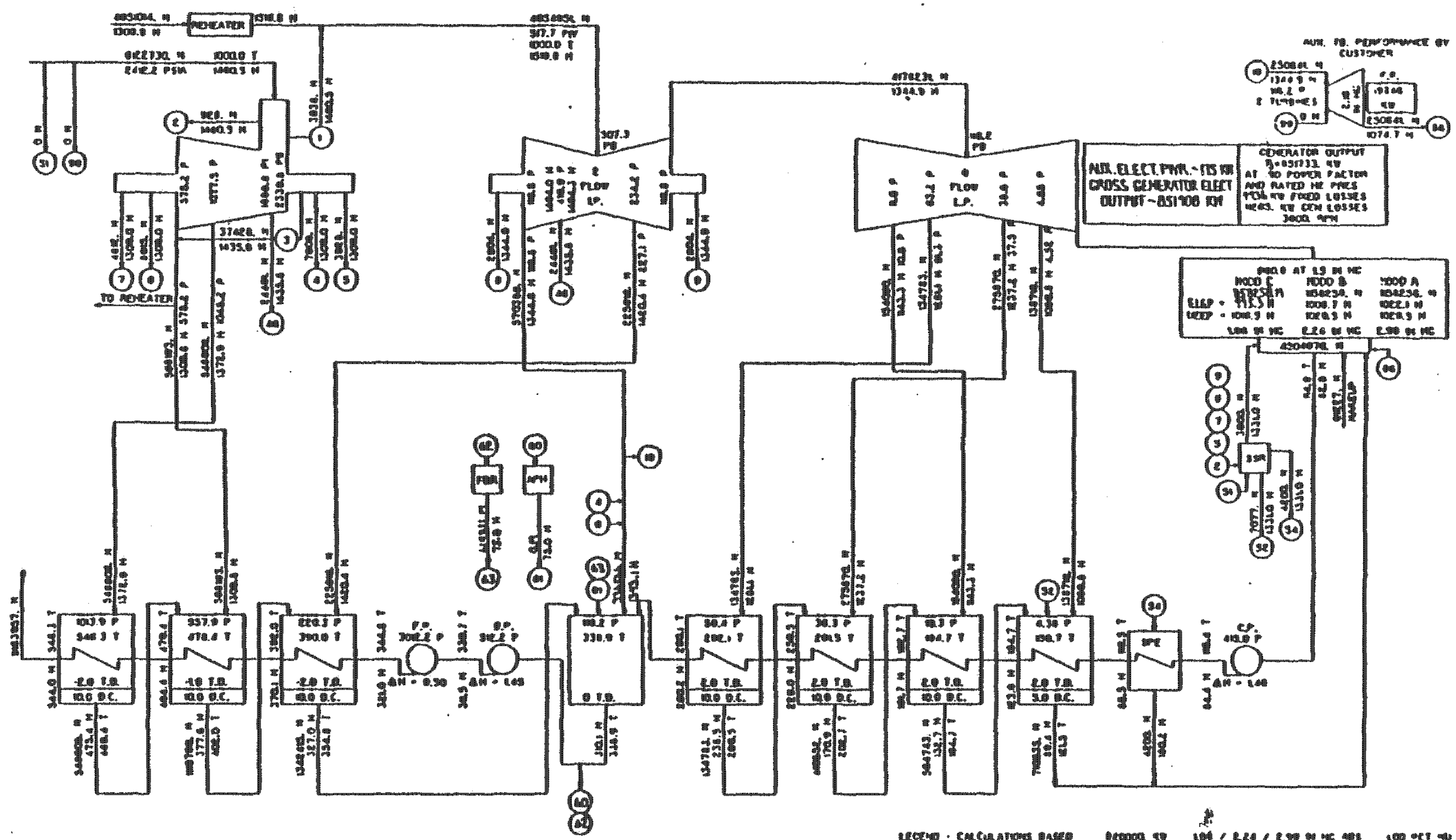
481 HB HE 0-24-01

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

CALCULATED DATA - NOT GUARANTEED

RATING FLOW IS 583871. W AT INLET STEAM CONDITIONS OF 2412.2 PSIA AND 1000.0 T
TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS
FROM EXPECTED VALUES, SHOP TOLERANCES ON OPENING AREAS, ETC WHICH MAY AFFECT THE FLOW, THE
TURBINE IS BEING DESIGNED FOR A DESIGN FLOW RATING FLOW PLUS 5.5 PERCENT OF 6122730. W



CUSTOMER DEFINED
VALVE BEST POINT = 6122730.W(1460.5H-544.0H)+4951014.W(1519.8H-1309.8H)+4504976.W(1.48H)+6123.W(720.5H-544.0H) / 851733 KW = 7818 BTU/KW-HR
NET HEAT RATE

LEGEND - CALCULATIONS BASED ON 1967 ASME STEAM TABLES
W - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

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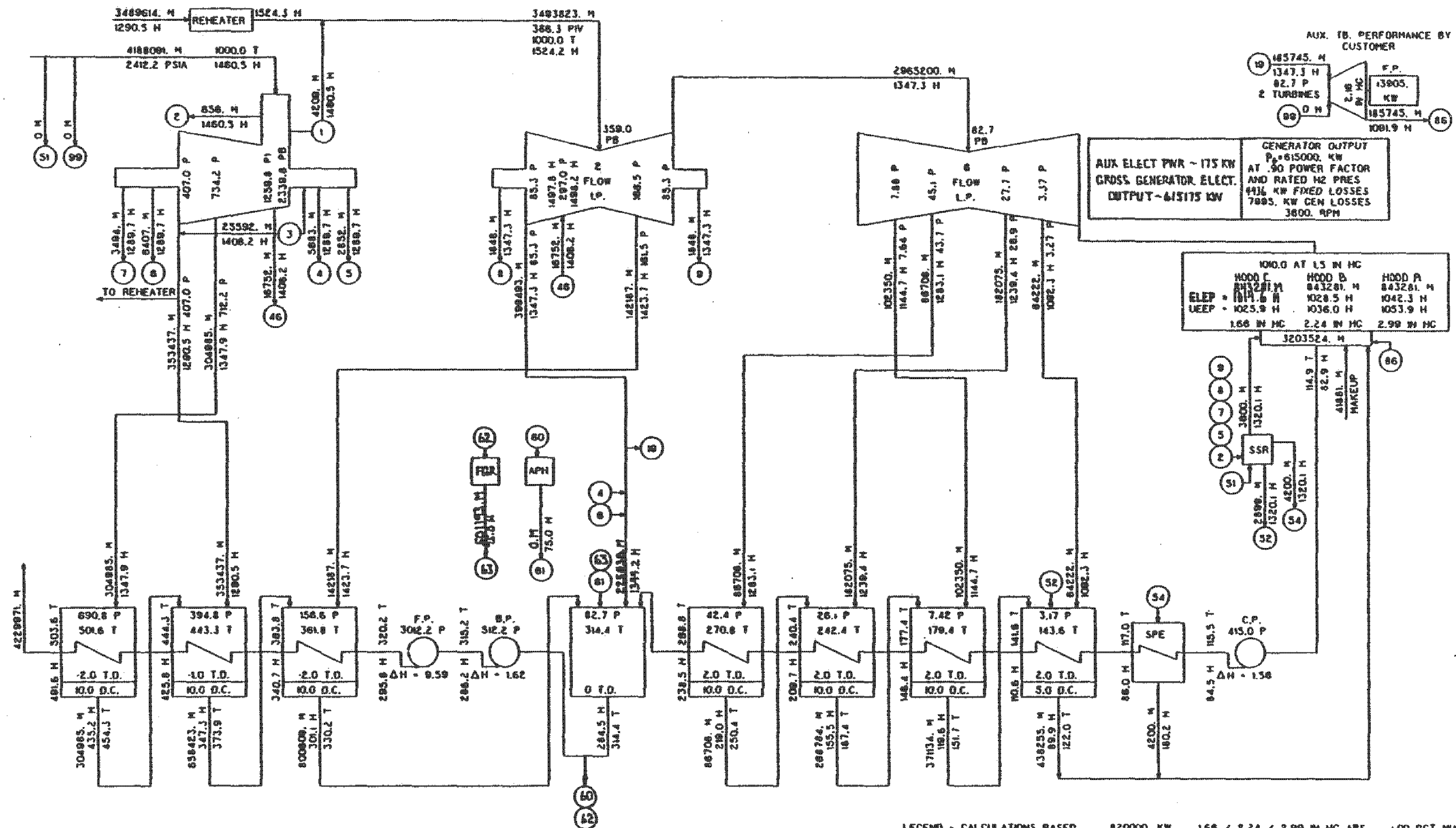
EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY



CUSTOMER DEFINED VALVE BEST POINT NET HEAT RATE = $\frac{4188091.M(1460.5H-491.6H)+3489614.M(1524.3H-1290.5H)+3203524.M(1.56H)+4188.M(720.5H-491.6H)}{615000\ KW} = 7934\ \frac{BTU}{KW/HR}$

LEGEND - CALCULATIONS BASED ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 991000. KVA .90 PF L10

KW Keam

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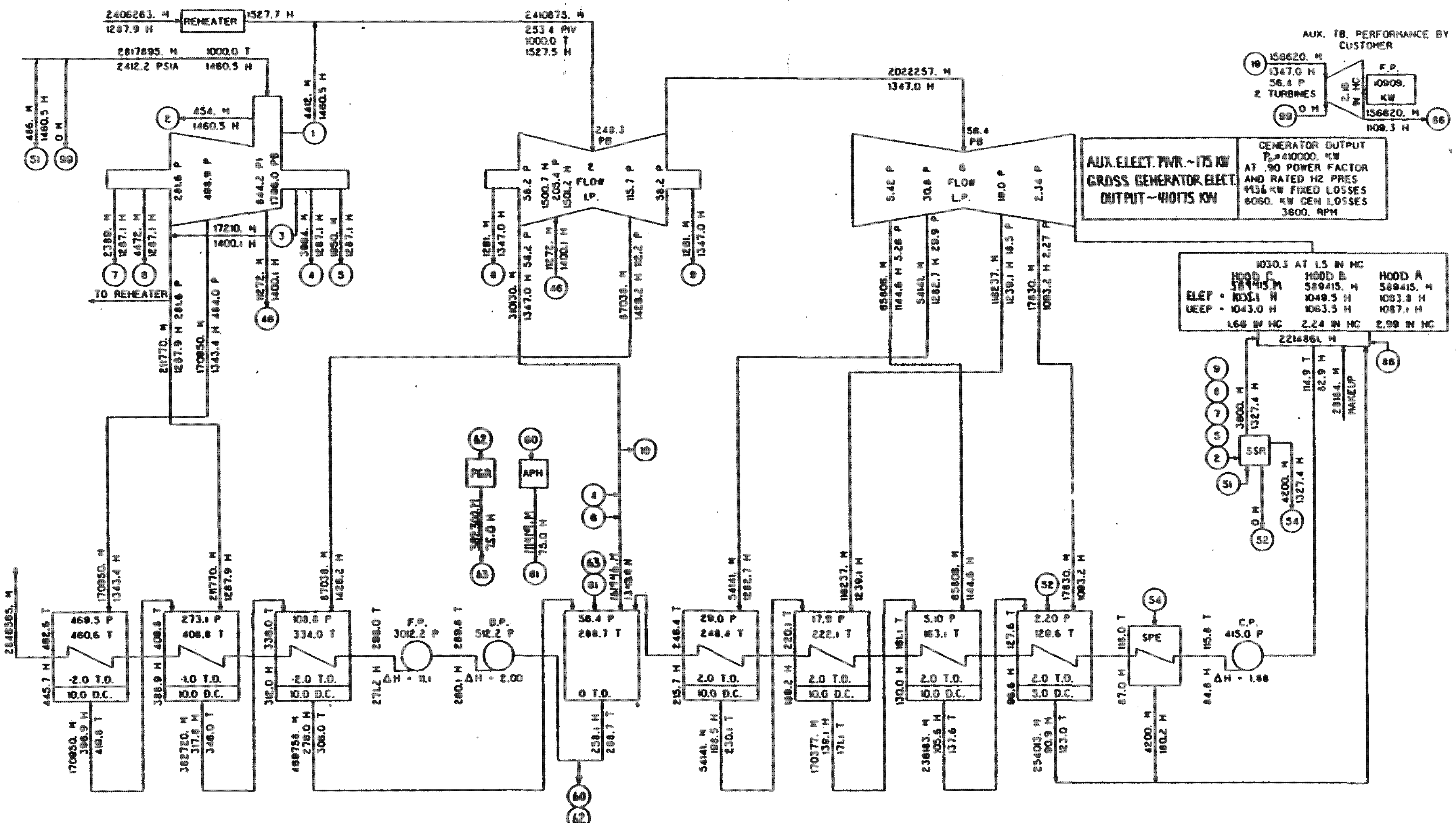
481 HB 147

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY



CUSTOMER DEFINED VALVE BEST POINT NET HEAT RATE = $\frac{2817895.M(1460.5H-445.7H)+2406263.M(1527.7H-1287.9H)+2214861.M(1.88H)+2818.M(720.5H-445.7H)}{410000 \text{ KW}}$ = 8394 $\frac{\text{BTU}}{\text{KW/HR}}$

LEGEND - CALCULATIONS BASED ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HG ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 991000. KVA .90 PF LIQ

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GENERAL ELECTRIC COMPANY. SCHENECTADY N.Y.

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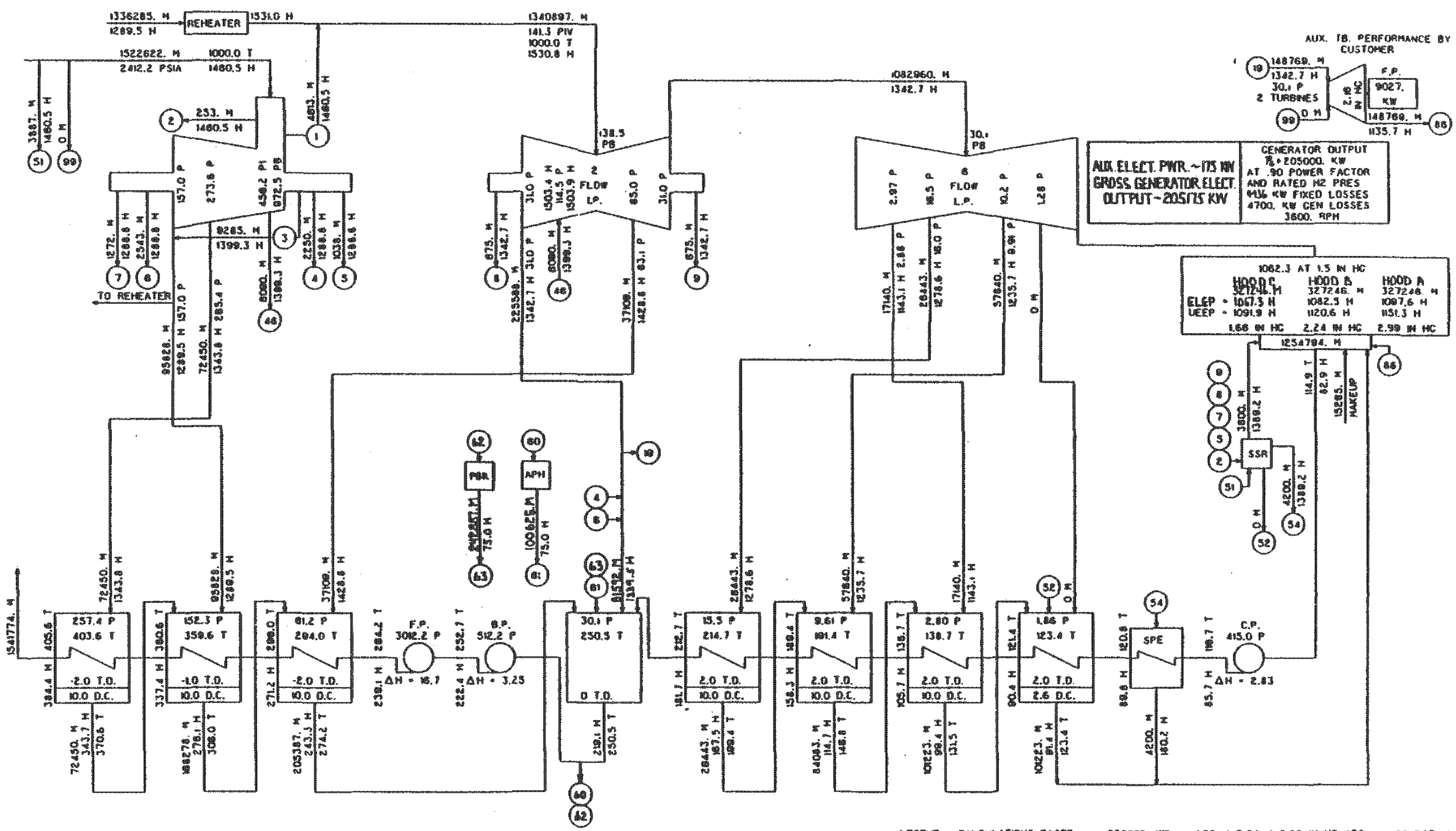
481 HB 148

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY



CUSTOMER DEFINED
VALVE BEST POINT
NET HEAT RATE

$$= \frac{1522622.M(1460.5H-384.4H)+1336285.M(1531.0H-1289.5H)+1254794.M(2.83H)+1523.M(720.5H-384.4H)}{205000\ KW} = 9587\ \frac{BTU}{KW/HR}$$

LEGEND - CALCULATIONS BASED
ON 1967 ASME STEAM TABLES
M - FLOW-LB/HR
P - PRESSURE-PSIA
H - ENTHALPY-BTU/LB
T - TEMPERATURE-F DEGREES

820000. KW 1.66 / 2.24 / 2.99 IN HC ABS. 1.00 PCT MU
TC6F 30.0 IN. LSB 3600 RPM
2400 PSIG 1000. / 1000. T
GEN- 991000. KVA .90 PF LIQ

KW Kora

534AT 1 DB0291 2486 0 15
481 HB 148 7-17-81

GENERAL ELECTRIC COMPANY, SCHENECTADY N.Y.

IP14_000623

452 HB 890

NET HEAT RATE CURVE

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.0 PCT MU
TC6F 30.0 IN LSB 3600 RPM
2400 PSIG 1000./1000. T

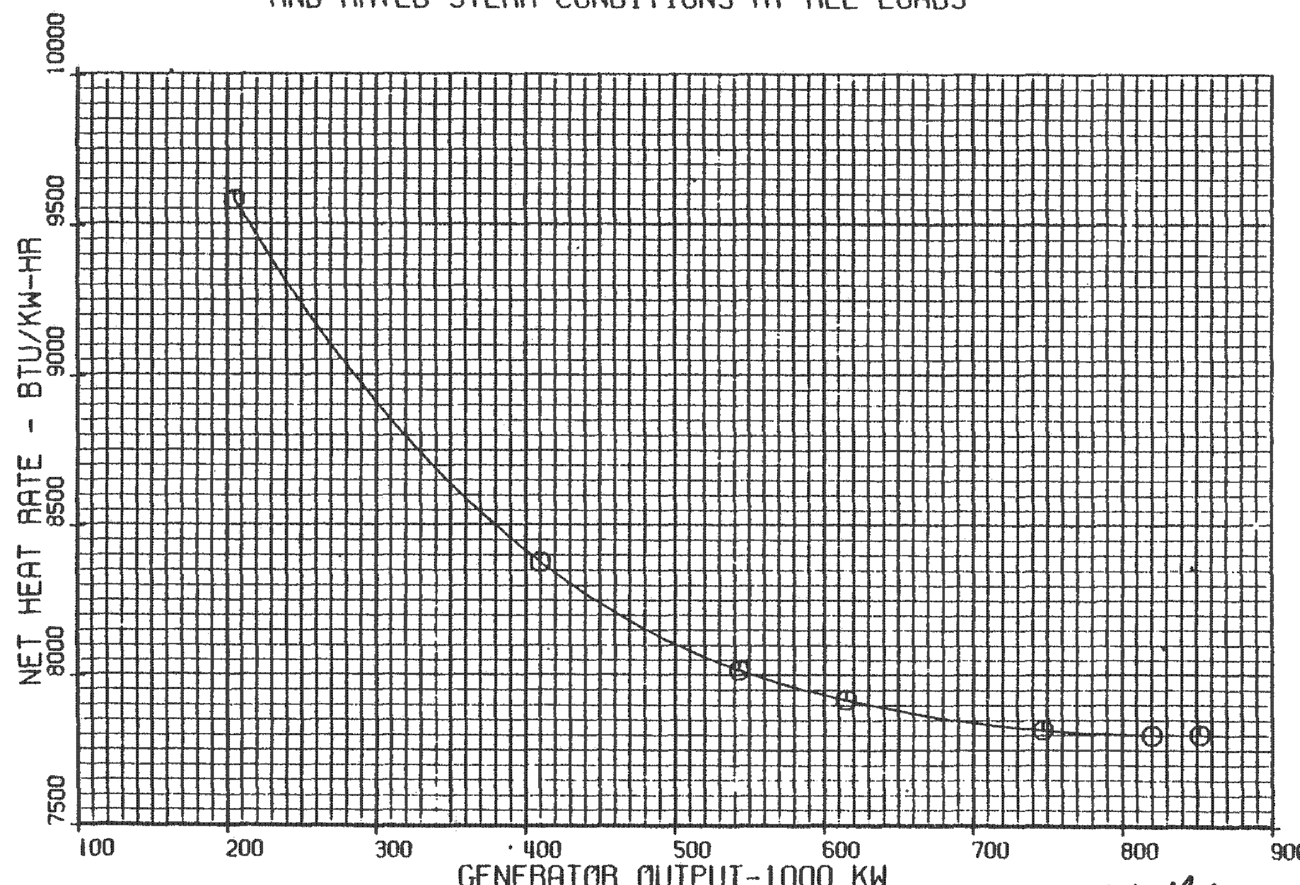
THESE HEAT RATES ARE BASED ON NORMAL EXTRACTION OPERATION AS SHOWN ON HEAT BALANCE 481 HB 111

DASHED PORTION OF CURVE IS AT FLOWS IN EXCESS OF RATING FLOW

CIRCLED POINTS REPRESENT POINTS THROUGH WHICH CURVE WAS DRAWN

THIS CURVE IS NOT GUARANTEED

THESE HEAT RATES ARE AT 1.66,2.24,2.99 IN.HG.ABS.EXH. PRESS.,1 PCT MU AND RATED STEAM CONDITIONS AT ALL LOADS



K.K. Major

GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK 11/30/81 452 HB 890

GENERATOR LOSSES
991000 KVA AT 63 PSIG H2 PRESS
CONDUCTOR COOLED 3600 RPM

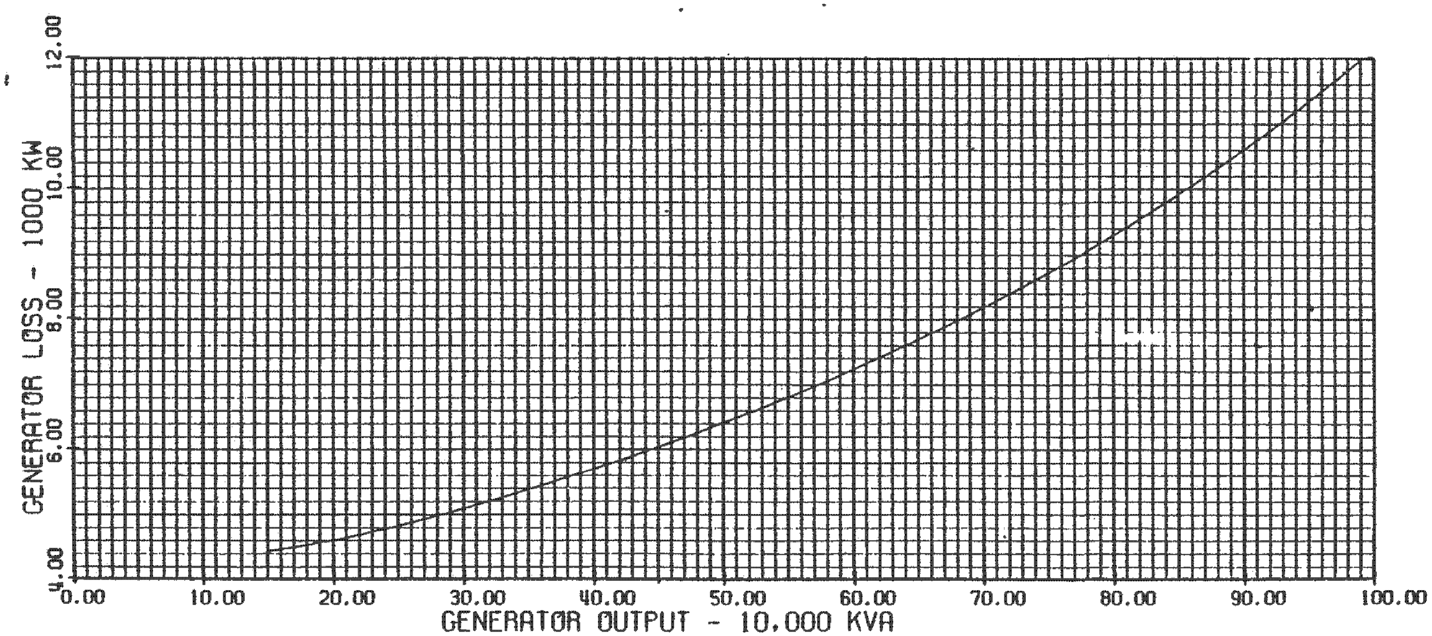
NOTES

GENERATOR LOSSES ASSUME RATED HYDROGEN PRESSURE AT ALL LOADS.

GENERATOR LOSS AT REDUCED HYDROGEN PRESSURE (P) = LOSS AT RATED HYDROGEN PRESSURE - 14.3 (P_{RATED} - P). USE GENERATOR REACTIVE CAPABILITY CURVE TO DETERMINE GENERATOR CAPABILITY AT REDUCED HYDROGEN PRESSURE.

TURBINE GENERATOR MECHANICAL LOSSES ARE NOT INCLUDED IN THE GENERATOR LOSS CURVE.

IF HYDROGEN AND STATOR LIQUID COOLERS ARE LOCATED IN THE CONDENSATE LINE, THE LOSS TRANSFERRED TO THE COOLERS IS 898 KW LESS THAN THE GENERATOR LOSS AT ALL LOADS.



GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK

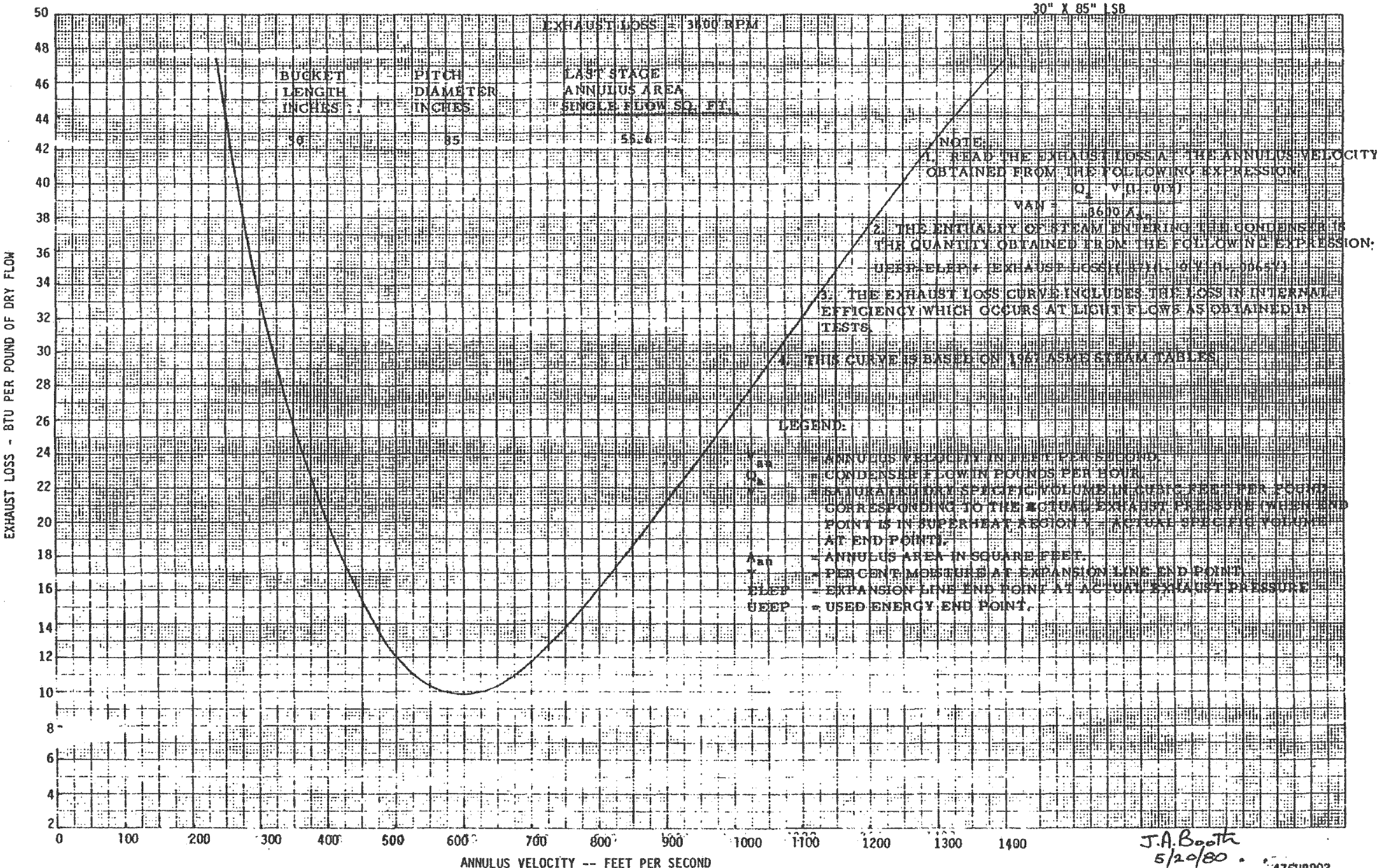
K. K. Major

12/01/81

452 HB 891

476HB902

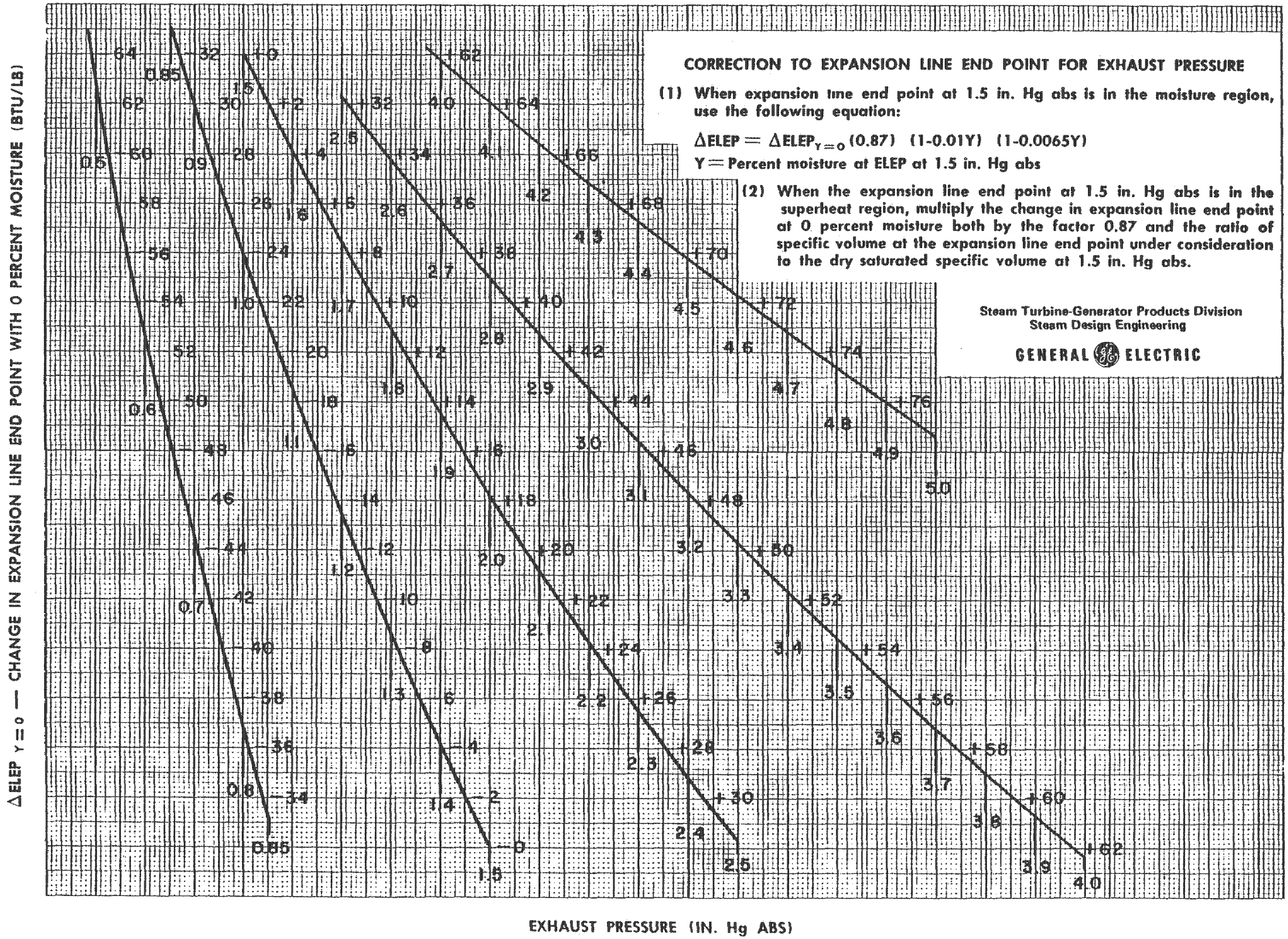
3600 RPM
30" X 85" LSB



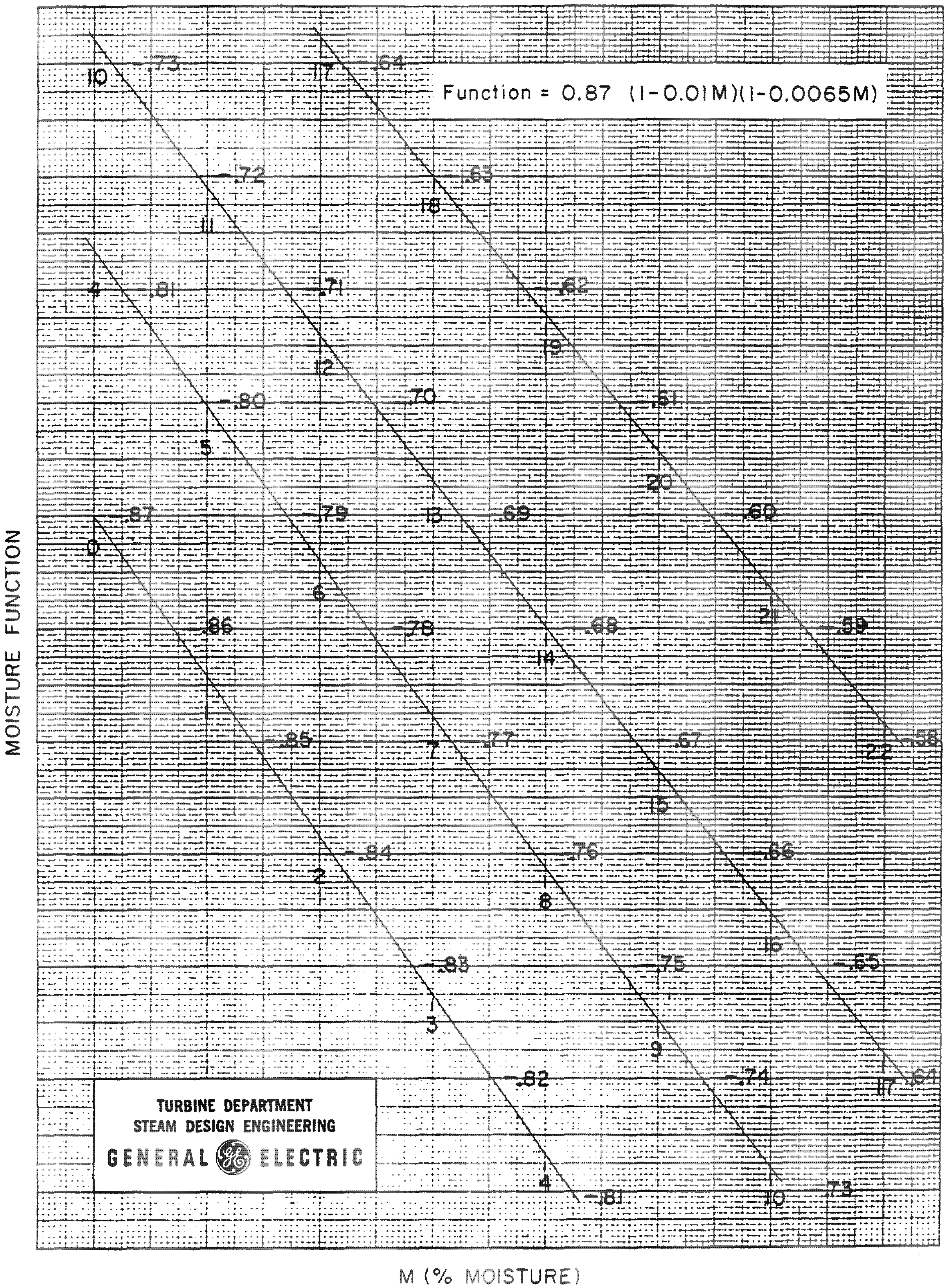
J.A. Booth
5/20/80

PRINTED IN U.S.A. 476HB902

IP14_000626


CORRECTION TO EXPANSION LINE END POINT FOR EXHAUST PRESSURE
(1) When expansion line end point at 1.5 in. Hg abs is in the moisture region, use the following equation:
$\Delta ELEP = \Delta ELEP_{Y=0} (0.87)\ (1-0.01Y)\ (1-0.0065Y)$
Y = Percent moisture at ELEP at 1.5 in. Hg abs
(2) When the expansion line end point at 1.5 in. Hg abs is in the superheat region, multiply the change in expansion line end point at 0 percent moisture both by the factor 0.87 and the ratio of specific volume at the expansion line end point under consideration to the dry saturated specific volume at 1.5 in. Hg abs.
Steam Turbine-Generator Products Division
Steam Design Engineering
GENERAL ELECTRIC
$\Delta ELEP_{Y=0}$ — CHANGE IN EXPANSION LINE END POINT WITH 0 PERCENT MOISTURE (BTU/LB)
EXHAUST PRESSURE (IN. Hg ABS)

IP14_000627

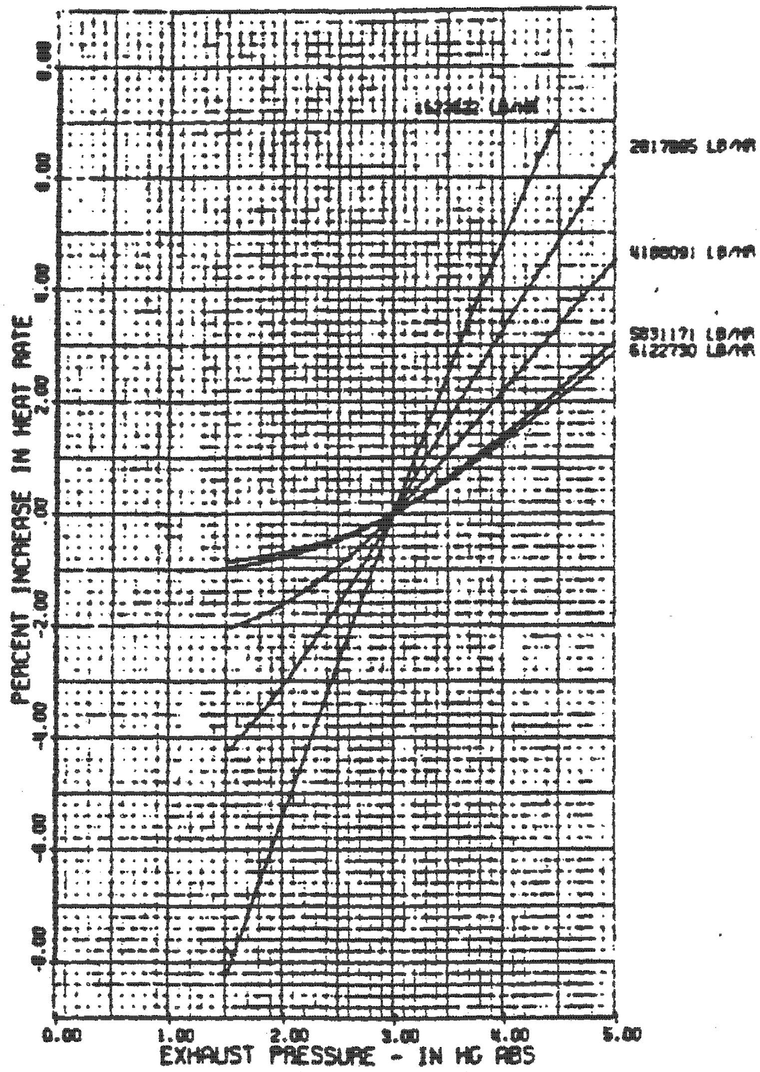

Function = 0.87 (1-0.01M)(1-0.0065M)
MOISTURE FUNCTION
M (% MOISTURE)
TURBINE DEPARTMENT
STEAM DESIGN ENGINEERING
GENERAL ELECTRIC

GEZ-5834

EXHAUST PRESSURE CORRECTION FACTORS

820000 KW AT 1.66/ 2.24/ 2.99 IN HG ABS 1.00 PCT MU
TC6F-30.0 IN LSB 3600 RPM
2400 PSIA 1000/1000 T

481 HB 475



METHOD OF USING CURVE

VALUES NEAR CURVES ARE FLOWS AT 2400 PSIA 1000 T
THESE CORRECTION FACTORS ASSUME CONSTANT CONTROL VALVE OPENING
APPLY CORRECTIONS TO HEAT RATE AND KW LOADS
AT 2.99/ 2.24/ 1.66 IN HG ABS AND 0.0 PCT MU.

THE PERCENT CHANGE IN KW LOAD FOR VARIOUS EXHAUST PRESSURES IS EQUAL TO
(MINUS PCT INCREASE IN HEAT RATE)100/(100 + PCT INCREASE IN HEAT RATE)

THESE CORRECTION FACTORS ARE NOT GUARANTEED

PRESSURES ALONG ABSCISSA ARE PRESSURES IN HOOD A

PRESSURE (IN HG ABS) FOR	HOOD A	HOOD B	HOOD C
	1.50	1.09	.78
	2.00	1.47	1.07
	2.50	1.85	1.36
	3.00	2.24	1.66
	3.50	2.63	1.96
	4.00	3.03	2.27
	4.50	3.42	2.58
	5.00	3.82	2.89

481 HB 475

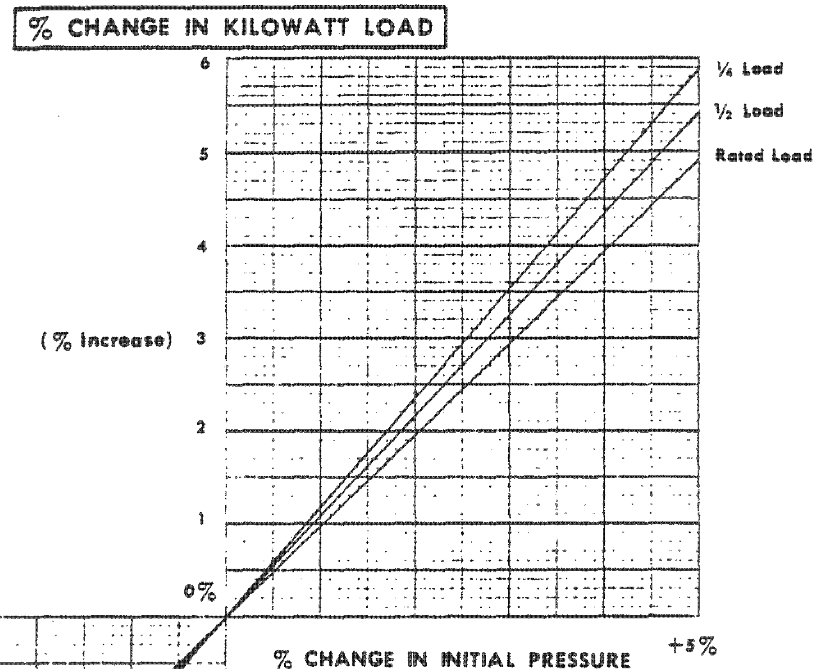
GENERAL ELECTRIC COMPANY. SCHENECTADY. NEW YORK 12/04/81

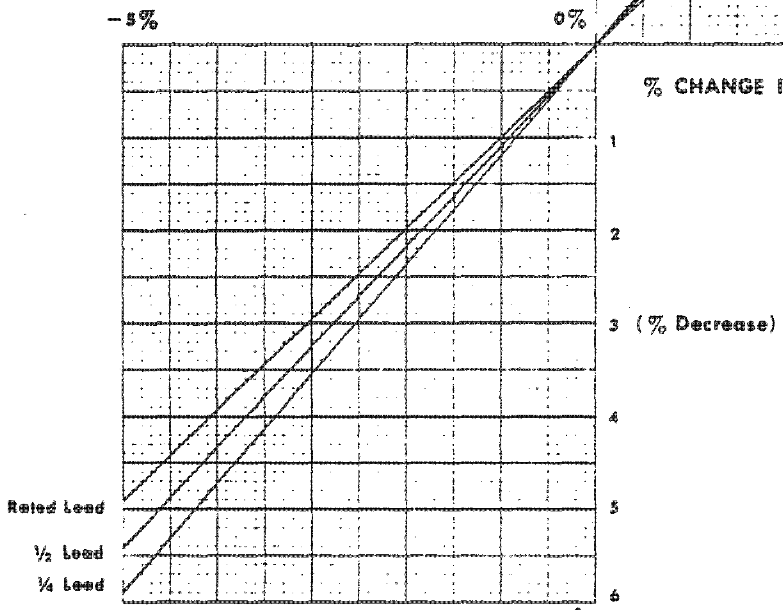
3/26/84 Rev.1

IP14_000629

INITIAL PRESSURE CORRECTION FACTORS

FOR SINGLE REHEAT UNITS





METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

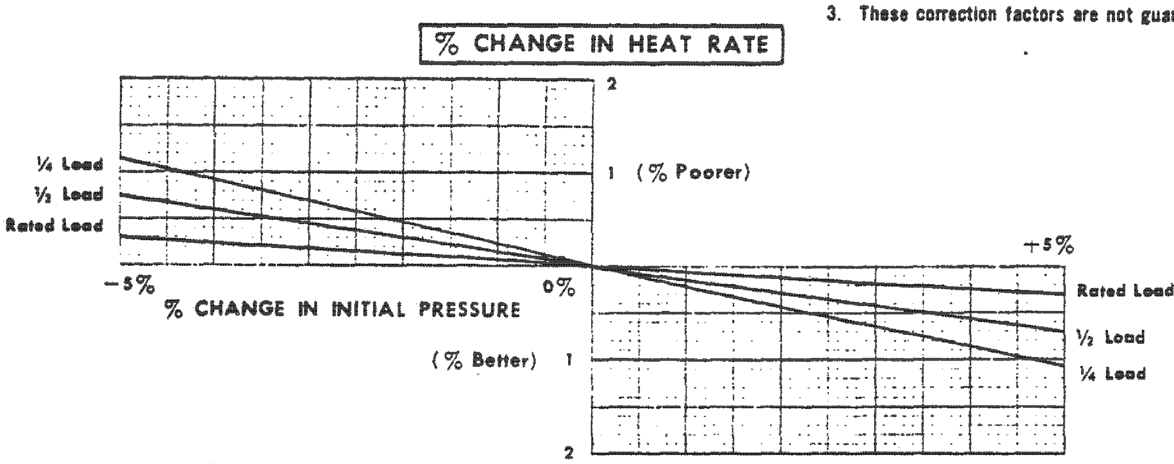
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\%\text{ change in gross heat rate}}{100}$$

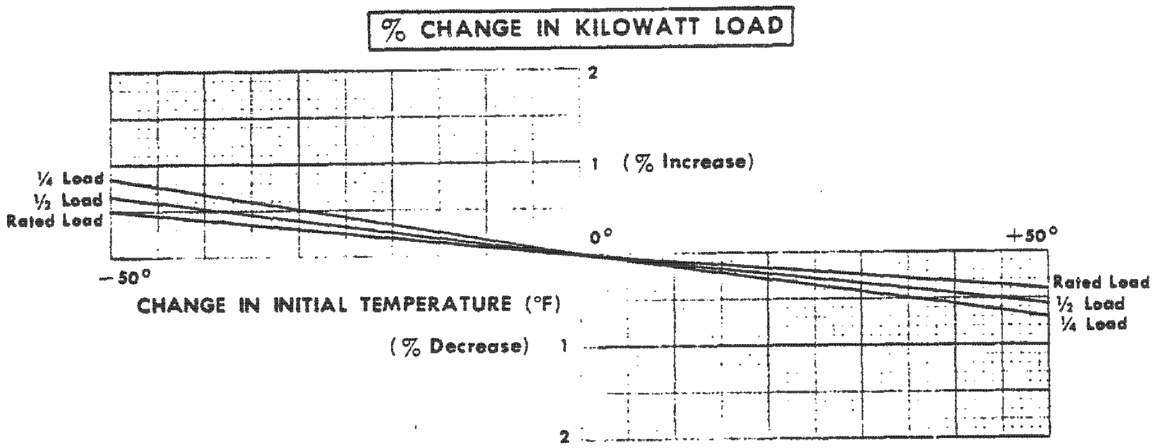
2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.



INITIAL TEMPERATURE CORRECTION FACTORS
FOR SINGLE REHEAT – SUBCRITICAL PRESSURE UNITS



METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

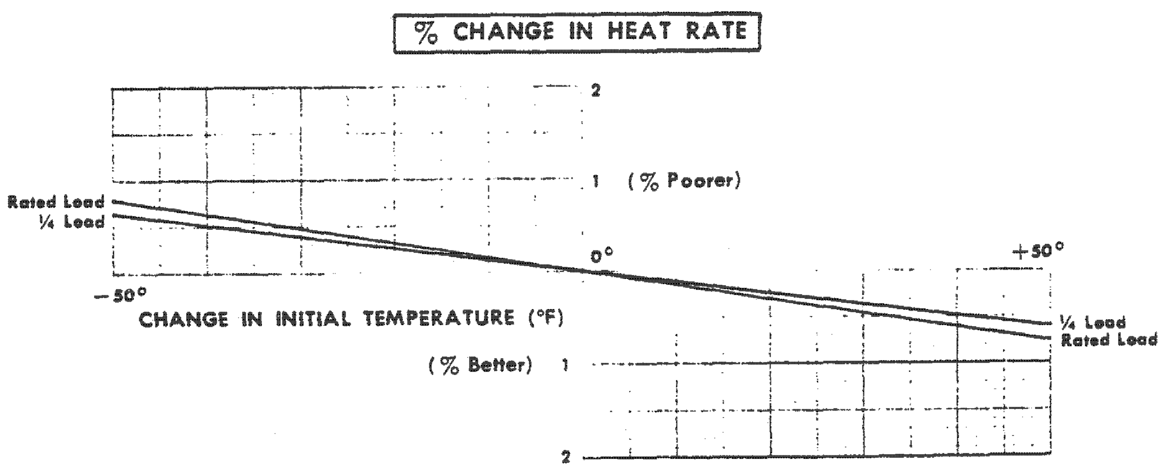
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\%\ \text{change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\ \text{change in kw load}}{100}$$

3. These correction factors are not guaranteed.

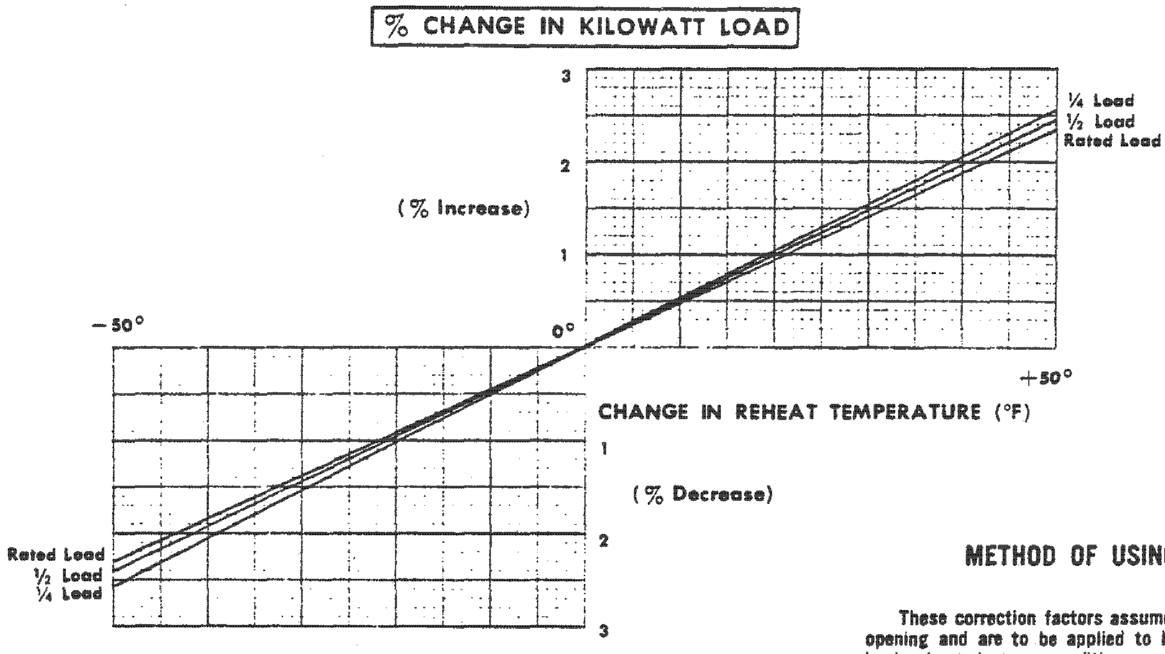


GEZ-3615
3-79 (2M)

GENERAL ELECTRIC

IP14_000631

REHEAT TEMPERATURE CORRECTION FACTORS
FOR SINGLE REHEAT UNITS



METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

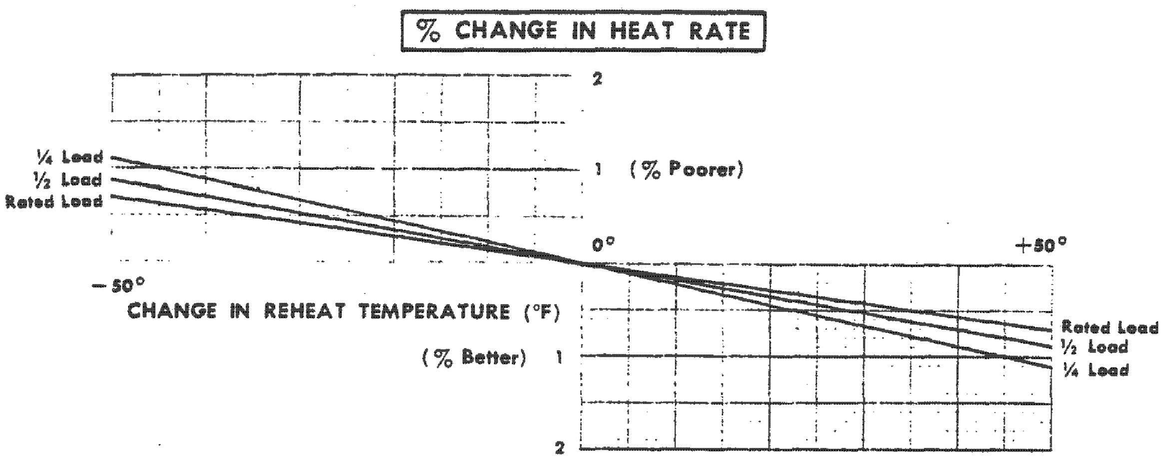
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\%\text{ change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.



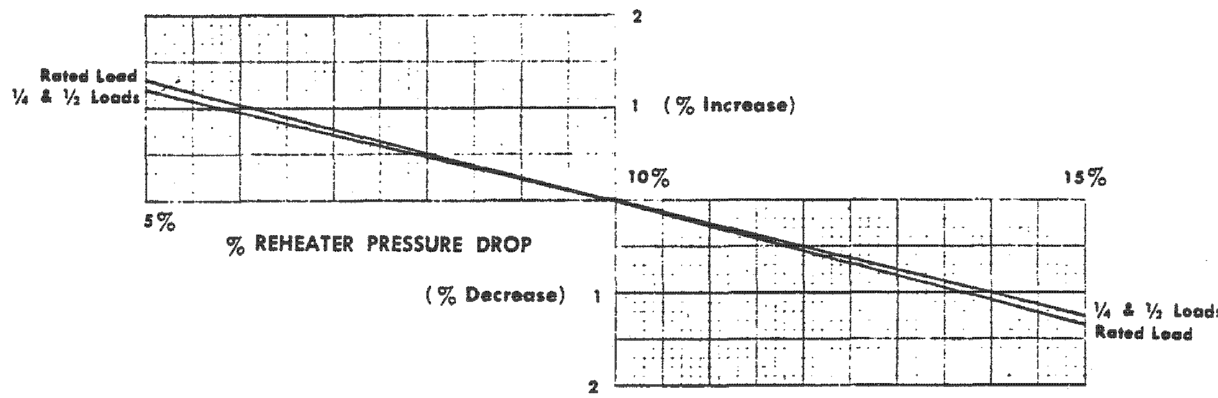
GEZ-3617
6–75 (2500)

GENERAL ELECTRIC

REHEATER PRESSURE DROP CORRECTION FACTORS

FOR SINGLE REHEAT UNITS

% CHANGE IN KILOWATT LOAD



METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

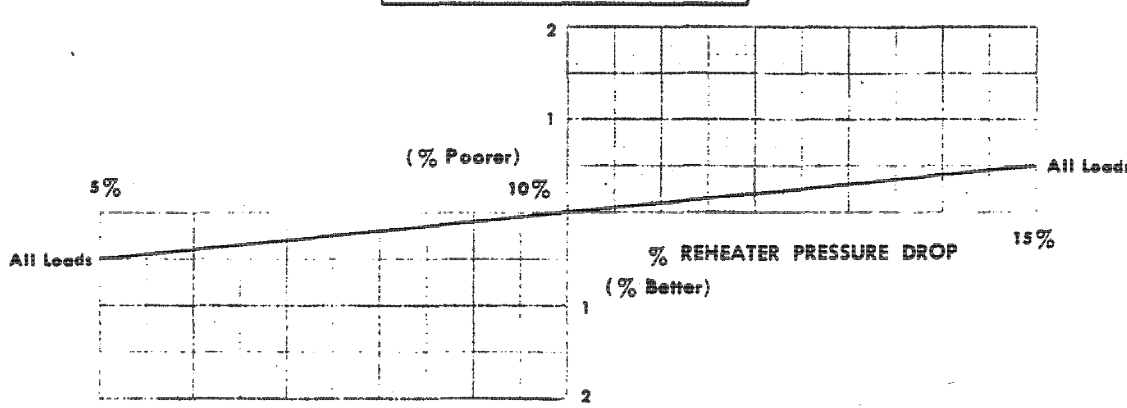
$$1 + \frac{\%\text{ change in gross heat rate}}{100}$$

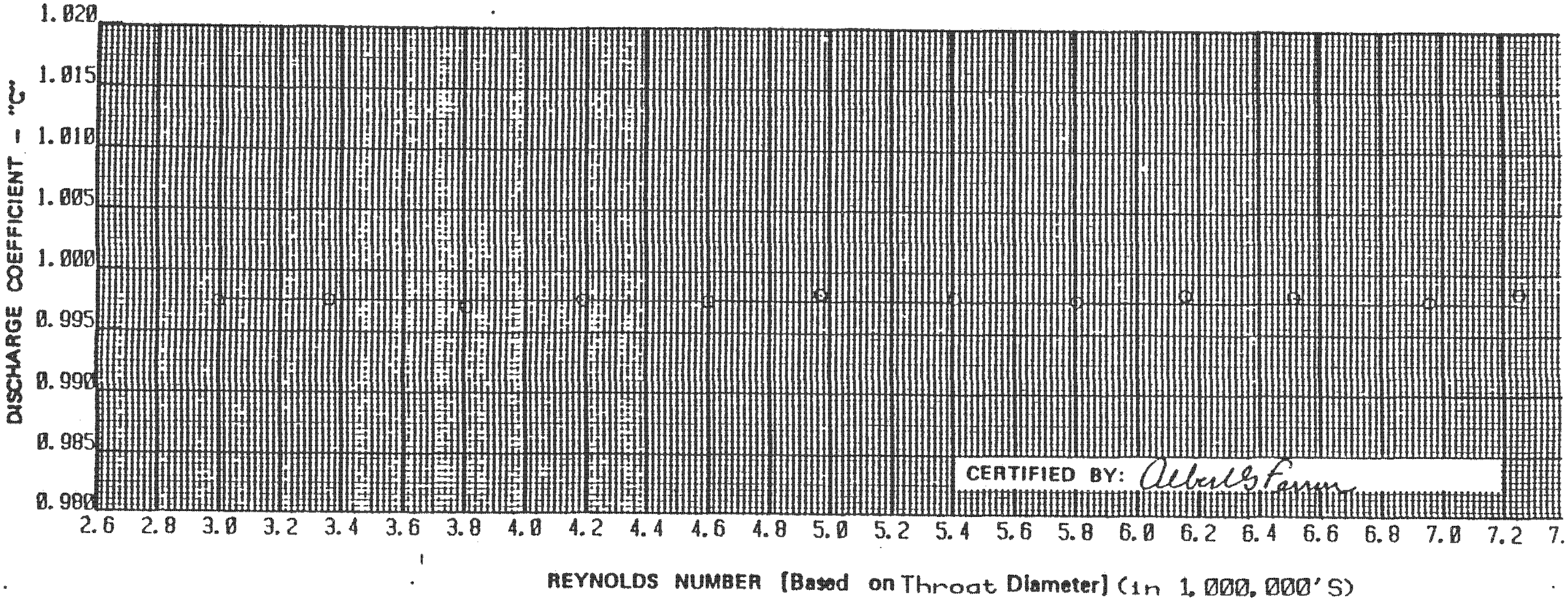
2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\%\text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.

% CHANGE IN HEAT RATE



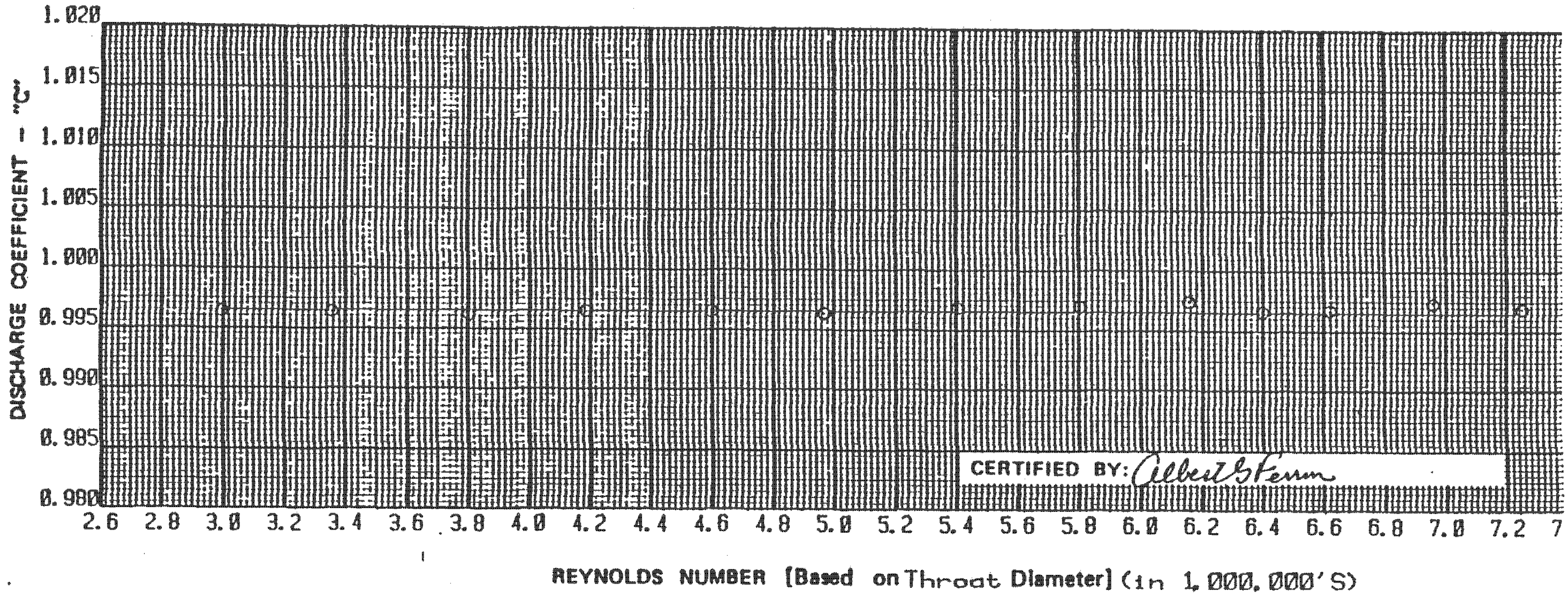


$q_a = C\ K_M \sqrt{h}$	
q_a = Actual Flow Rate (ft^3/sec)	
C = Discharge Coefficient — Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
K_M = Meter Constant = $\frac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ =	4.3092
F_a = Thermal Expansion Factor =	1.0005
a = Throat Area (ft^2) =	0.5283
g = Local Acceleration of Gravity (ft/sec^2)	32.163
β = Dimensionless Ratio of Throat to Pipe Diameter =	0.4233
Upstream Diameter =	23.250
Throat Diameter =	9.842
Dimensions By: DANIEL	

MEAN -- 0.9977 ABOVE THROAT
REYNOLDS # 2900000

TAP SET # A
24" FLOW NOZZLE ASSEMBLY
TAG NUMBER: 9 FWCF51-FE-0010
DANIEL INDUSTRIES, INC.
PO NUMBER: 77256
OCTOBER 1, 1984

ARL



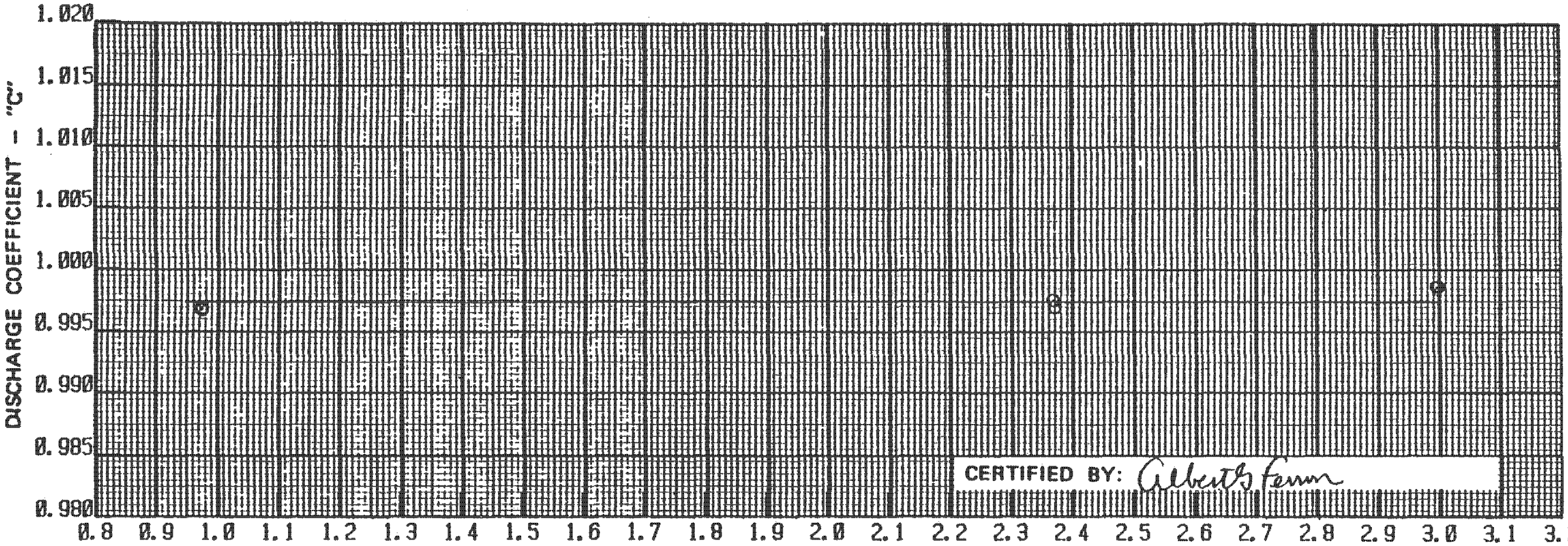
$q_a = C\ K_M \sqrt{h}$	
q_a = Actual Flow Rate (ft^3/sec)	
C = Discharge Coefficient — Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
K_M = Meter Constant = $\dfrac{a\sqrt{2g} \times Fa}{\sqrt{1-\beta^4}}$ =	4.3092
F_a = Thermal Expansion Factor =	1.0005
a = Throat Area (ft^2) =	0.5283
g = Local Acceleration of Gravity (ft/sec^2)	32.163
β = Dimensionless Ratio of Throat to Pipe Diameter =	0.4233
Upstream Diameter =	23.250
Throat Diameter =	9.842
Dimensions By: DANIEL	

MEAN - 0.9985 ABOVE THROAT
REYNOLDS # 2000000

TAP SET # B
24" FLOW NOZZLE ASSEMBLY
TAG NUMBER: 9 FWCF51-FE-0010
DANIEL INDUSTRIES, INC.
PO NUMBER: 77256
OCTOBER 1, 1984

ARL

IP14_000635



$$q_a = C\ K_M \sqrt{h}$$

q_a = Actual Flow Rate (ft^3/sec)	
C = Discharge Coefficient — Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
K_M = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ =	2.7369
F_a = Thermal Expansion Factor =	1.0004
a = Throat Area (ft^2) =	0.3323
g = Local Acceleration of Gravity (ft/sec^2)	32.163
β = Dimensionless Ratio of Throat to Pipe Diameter =	0.4749
Upstream Diameter =	16.4351
Throat Diameter =	7.8055
Dimensions By: B. I. F.	

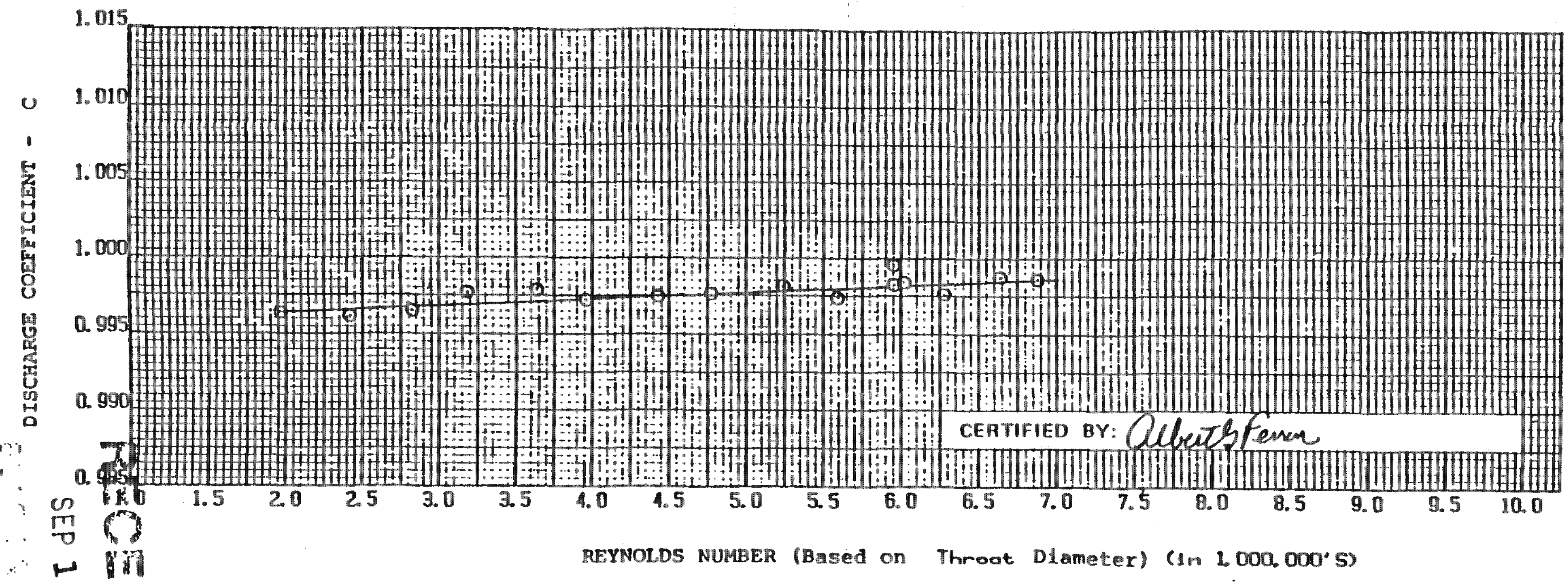
WITH GASKET ON INSPECTION PORT

MEAN - 0.9975 ABOVE PIPE
REYNOLDS # 900000

TAP SET # 1
20" PTC-6 TEST SECTION
SERIAL NUMBER: 90915-1
B. I. F.
PO NUMBER: 70378-KO
MAY 9, 1984

ARL

IP14_000636



RECEIVED
SEP 16 1985

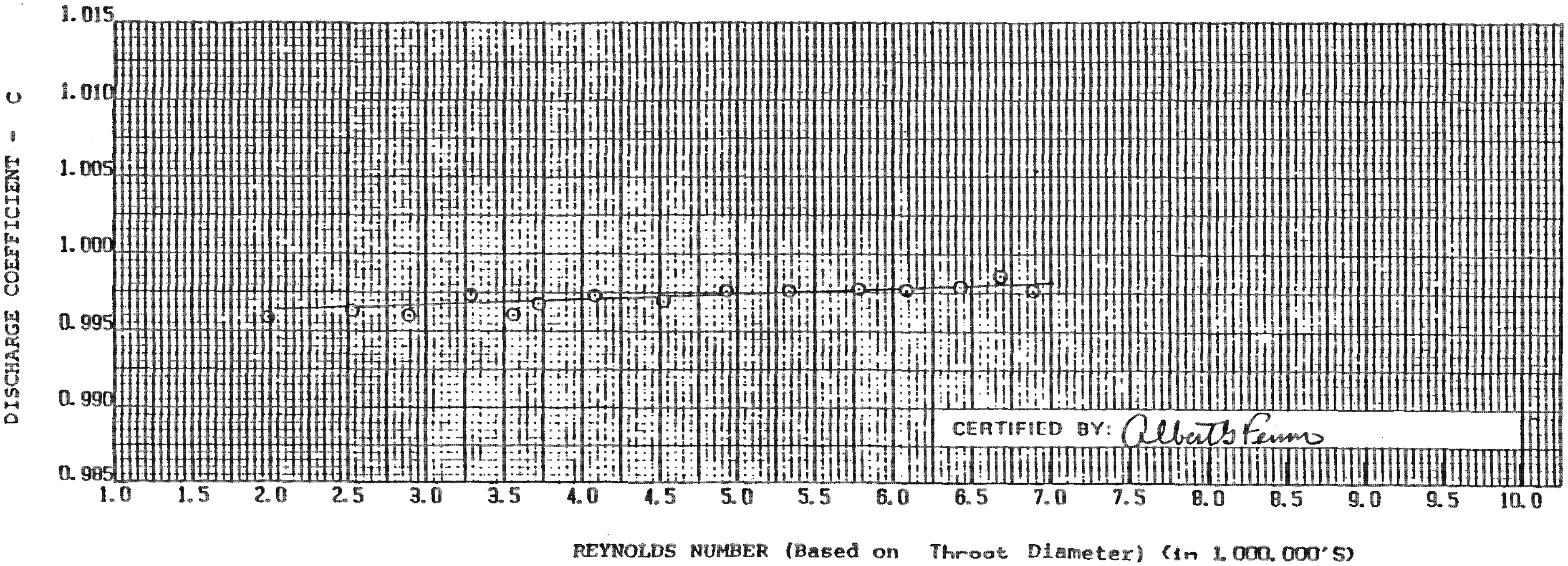
$q_a = C\ K_M \sqrt{h}$

q_a Actual Flow Rate (ft^3/sec)	
C = Discharge Coefficient - Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
K_M = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ =	2.7262
F_a = Thermal Expansion Factor =	1.0006
a = Throat Area (ft^2) =	0.3325
g = Local Acceleration of Gravity (ft/sec^2)	32.163
β = Dimensionless Ratio of Throat to Pipe Diameter =	0.4525
Upstream Diameter =	17.254
Throat Diameter =	7.8080
Dimensions By: DANIEL	

TAP SET # A
18" FLOW NOZZLE ASSEMBLY
SERIAL NUMBER: 85-110134
DANIEL INDUSTRIES INCORPORATED
PO NUMBER: 1-PO-81459
MAY 15, 1985

ARL

IP14_000637



$$q_a = C\, K_M \sqrt{h}$$

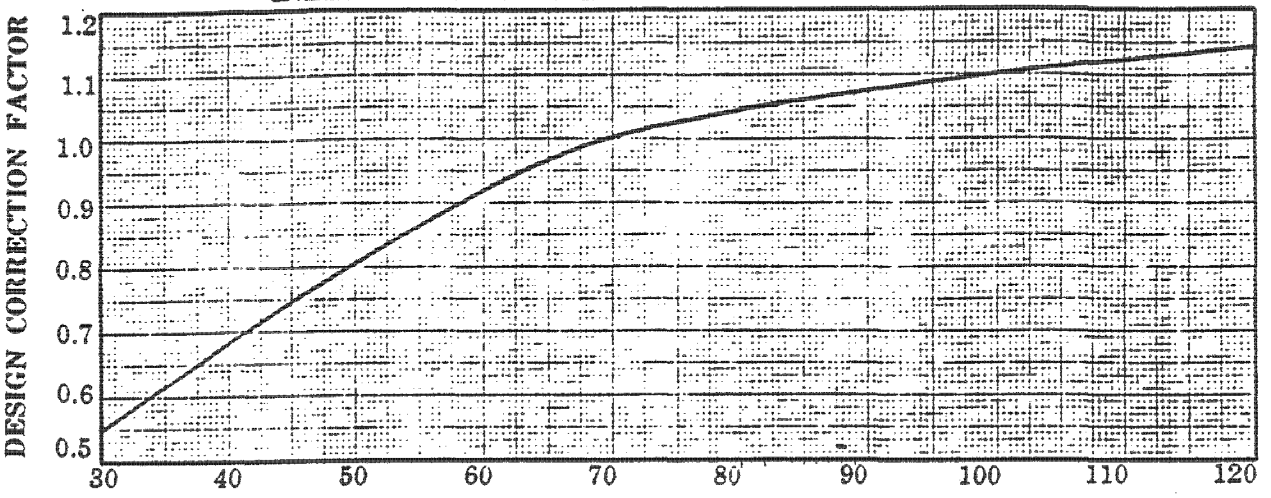
q_a = Actual Flow Rate (ft^3/sec)	
C = Discharge Coefficient - Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
K_M = Meter Constant = $\dfrac{a\sqrt{2g} \times F_a}{\sqrt{1-\beta^4}}$ =	2.7255
F_a = Thermal Expansion Factor =	1.0008
a = Throat Area (ft^2) =	0.3324
g = Local Acceleration of Gravity (ft/sec^2)	32.163
β = Dimensionless Ratio of Throat to Pipe Diameter =	0.4523
Upstream Diameter =	17.259
Throat Diameter =	7.8070
Dimensions By: DANIEL	

TAP SET # A
18" FLOW NOZZLE ASSEMBLY
SERIAL NUMBER: 85-110135
DANIEL INDUSTRIES INCORPORATED
PO NUMBER: 1-PO-81459
MAY 15, 1985

ARL

IP14_000638

INLET WATER TEMPERATURE CORRECTION FACTOR



TEMPERATURE OF INLET WATER DEGREES F

Fig. 2